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Integrated Safety Assessment Report

Integrated Safety Assessment Program

Millstone Nuclear Power Station, Unit 1

Northeast Nuclear Energy Company
Docket No. 50-245

Draft Report

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

April 1987

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ABSTRACT

The Integrated Safety Assessment Program (ISAP) was initiated in November 1984, by the U.S. Nuclear Regulatory Commission to conduct integrated assessments for operating nuclear power reactors. The integrated assessment is conducted on a plant-specific basis to evaluate all licensing actions, licensee initiated plant improvements and selected unresolved generic/safety issues to establish implementation schedules for each item. In addition, procedures will be established to allow for a periodic updating of the schedules to account for licensing issues that arise in the future.

This report documents the review of Millstone Nuclear Power Station, Unit No. 1, operated by Northeast Nuclear Energy Company (located in Waterford, Connecticut). Millstone Nuclear Power Station, Unit No. 1, is one of two plants being reviewed under the pilot program for ISAP. This report indicates how 85 topics selected for review were addressed. This report presents the staff's recommendations regarding the corrective actions to resolve the 85 topics and other actions to enhance plant safety. The report is being issued in draft form to obtain comments from the licensee, nuclear safety experts, and the Advisory Committee for Reactor Safeguards (ACRS). Once those comments have been resolved, the staff will present its positions, along with a long-term implementation schedule from the licensee, in the final version of this report.

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ACRONYMS AND INITIALISMS

ABT - automatic bus transfer
AC - alternating current
ACI - American Concrete Institute
ACRS - Advisory Committee on Reactor Safeguards
ADS - automatic depressurization system
AISC - American Institute of Steel and Concrete
ALARA - as low as reasonably achievable
ANPR - advance notice of proposed rulemaking
ARM - Analytical Ranking Model
ASME - American Society of Mechanical Engineers
ATWS - anticipated transients without scram
BOP - balance of plant
BTP - branch technical position
BWR - boiling water reactor
CFM - cubic feet per minute
CFR - *Code of Federal Regulations*
CMF - core melt frequency
CO - control room operator
CRD - control rod drive system
CST - condensate storage tank
DBE - design basis event
DC - direct current
ECCS - emergency core cooling system
EPG emergency procedures guideline
EQ equipment qualification
ERF - emergency response facility
ESF - engineered safety feature
F - degrees Fahrenheit
FR - *Federal Register*
FSAR - final safety analysis report
FTOL - full term operating license
FWCI - feedwater coolant injection
GDC - General Design Criterion
GESSAR - General Electric Standard Safety Analysis Report
GL - Generic Letter
GTG - gas turbine generator
HVAC - heating, ventilation and air conditioning
IAPM - Integrated Assessment Project Manager
IAT - Integrated Assessment Team
IC - isolation condenser
IE - Office of Inspection and Enforcement
IEEE - Institute of Electronics and Electrical Engineers
IGSCC - intergranular stress corrosion cracking
IIS - Integrated Implementation Schedule
INPO - Institute of Nuclear Power Operations
IPSAR - Integrated Plant Safety Assessment Report
IREP - Interim Reliability Evaluation Program
ISAP - Integrated Safety Assessment Program
ISAR - Integrated Safety Assessment Report
LER - licensee event report
LNP - loss of normal power
LOCA - loss of coolant accident
LPCI - low pressure coolant injection

LPRM - low power range monitor
MEPL - Material, Equipment and Parts List
MOV - motor-operated valve
MSIV - main steam isolation valve
MSL - main steam line
MSRVDL - main steam relief valve drain line
MWt - megawatt-thermal
NNECO - Northeast Nuclear Energy Company
NPSH - net positive suction head
NRC - U. S. Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
NSSS - nuclear steam supply system
NU - Northeast Utilities
ORNL - Oak Ridge National Laboratory
ORPM - Operating Reactor Project Manager
OSHA - Occupational Safety and Health Administration
P&ID - piping and instrumentation diagram
PASS - post-accident sampling system
PMMS - Production Maintenance Management System
PSA - Probabilistic Safety Assessment
PSIM - public safety impact model
PWR - pressurized water reactor
QA - quality assurance
RAM - reliability/availability/maintainability model
RBCCW - reactor building closed cooling water
RHR - residual heat removal
RPS - reactor protection system
RWCU - reactor water cleanup
Rev - revision
SAIC - Science Applications International Corporation
SALP - Systematic Assessment of Licensee Performance
SCFH - standard cubic feet per hour
SCO - senior control room operator
SDV - scram discharge volume
SEP - Systematic Evaluation Program
SER - safety evaluation report
SLCS - standby liquid control system
SPDS - safety parameter display system
SRP - Standard Review Plan
SRO - senior reactor operator
SRV - safety relief valve
SS - shift supervisor
STA - shift technical advisor
TBD - to be determined
TMI-2 - Three Mile Island Unit No. 2
TS - technical specification
USI - Unresolved Safety Issue
UT - ultrasonic test
V - volt
ft - foot/feet
gpm - gallons per minute
h - hour
in - inch(es)
yr - year
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EXECUTIVE SUMMARY

The Integrated Safety Assessment Program (ISAP) was initiated in November 1984, by the U. S. Nuclear Regulatory Commission to conduct integrated assessments for operating nuclear power reactors. The integrated assessment is conducted on a plant-specific basis to evaluate all licensing actions, licensee initiated plant improvements and selected unresolved generic/safety issues to establish implementation schedules for each item. In addition, procedures will be established to allow for a periodic updating of the schedules to account for licensing issues that arise in the future.

The goal of ISAP is to provide a stable review environment to allow the development of an integrated schedule for more efficient and effective implementation of requirements and licensee initiated plant improvement projects. The ISAP review is divided into 5 parts, which are: (1) the issue screening review; (2) the ISAP evaluations; (3) the integrated assessment; (4) draft integrated safety assessment report issuance and comment period; and (5) establishment of an integrated schedule and schedule update plan.

The screening review was performed by a dedicated staff review team (the Integrated Assessment Project Manager, the Operating Reactor Project Manager, the Resident Inspector and a Reliability Analyst) and the licensee. The screening review was performed to delete those issues from review which were not appropriate for or would not benefit from the ISAP process. Deletion criteria were developed and applied to a compilation of all requirements, issues and projects that were currently scheduled for action at Millstone Nuclear Power Station, Unit No. 1 resulting in 80 topics to be considered in ISAP. Also, as part of the basis for deferring action on outstanding actions, the staff and licensee, Northeast Nuclear Energy Company (NNECO), developed an appropriate work load for both the engineering and operations staff at NNECO while the ISAP review was in progress (see Sections 1 and 2).

The ISAP evaluations were divided into three parallel phases: topic evaluations; performance of a probabilistic safety assessment (PSA); and the evaluation of operating experience. The ISAP topic evaluations were conducted in a manner similar to that used in the Systematic Evaluation Program (see NUREG-0824). The staff performed a review of the licensee's analyses for the topics to confirm the completeness of the items to be considered (see Section 2.2). NNECO conducted a plant-specific PSA and submitted a PSA summary for staff review. NNECO also submitted PSA evaluations for those ISAP topics for which risk assessments were amenable (see Section 2.3). The operating experience evaluation was performed by the staff and consisted of a review of forced shutdowns and reportable events at Millstone Unit No. 1, together with the Systematic Assessment of Licensee Performance reports (see Section 2.4).

As a result of the PSA and operating experience review by the staff, three new topics were developed for consideration in the ISAP review. In addition, during the course of the ISAP review, NNECO supplied two more topics for review, bringing the total number of topics to be reviewed in ISAP to 85 (see Section 2.6).

As stated in the Commission Policy Statement on ISAP (49 FR 45112, see Appendix A), any issues that arose during the ISAP review which the staff determined warrant prompt action to ensure the health and safety or common defense and security of the public would be implemented immediately. During the course of the ISAP review, NNECO made several plant and procedural modifications which were motivated by the results of their PSA. The modifications include:

- revised surveillance procedures for the LPCI pump motor bearing lube oil cooling;
- revised preventive maintenance program to improve the emergency service water to LPCI cross-tie valve reliability;
- modified valve operator and switch logic for MOV 1-IC-3 (isolation condenser condensate return line valve) and replaced 1-IC-3 with a smaller valve;
- corrected LPCI and core spray pump throttling procedures;
- corrected LPCI loop selection wiring error on the LPCI system injection valves;
- modified emergency procedures to bypass, at the discretion of the operator, potential drywell cooler lockout;
- changed preferred power source on valve SW-9 (isolates nonessential service water cooling loads); and
- replaced valve operator for 1-IC-1 (isolation condenser steam isolation valve).

(Refer to Sections 3.3 and 3.4 and Appendix D for more detail)

The staff reviewed the list of unresolved generic safety issues in NUREG-0933 and identified five additional areas that were considered in ISAP. These areas are: (1) reliability assurance; (2) station blackout; (3) severe accidents; (4) Mark I containments; and (5) external events. The staff made recommendations for evaluations to be made by NNECO that would expand the present scope of the PSA, provide for a greater understanding of plant operating characteristics, result in a reduction of core melt frequency, and resolve parts or all of these 5 issues at Millstone Unit No. 1 (see Section 3.4 and Appendix D).

In addition to identifying issues requiring prompt action and additional topics for consideration in the ISAP review, the ISAP evaluation process (topic evaluations, PSA and operating experience reviews) resulted in an improved integrated knowledge of plant operations and capability at Millstone Unit No. 1. It is NNECO's objective to incorporate the ISAP process more directly into its daily routine for conducting business. This activity would include increased formalization of the ISAP process and the development of the internal mechanisms via which information on projects is obtained and fed back through the ISAP process.

This draft integrated safety assessment report (ISAR) documents the review of Millstone Unit No. 1, which is one of two plants being reviewed under the pilot program for ISAP. This draft report indicates how 85 topics selected for review were addressed and presents the staff's recommendations regarding the corrective actions to resolve the 85 topics and other actions to enhance plant safety. The draft ISAR serves as the vehicle to resolve all of the outstanding issues. The draft ISAR is being issued to the licensee for comment, the ACRS and peer review experts. In the event that the staff and licensee disagree on the resolution of any given issue, that difference would be aired during the comment period in accordance with established NRC appeal procedures and ultimately presented to the Commission as a policy issue for action, if necessary. The resolution will appear in the final ISAR.

The licensee was also requested to propose an integrated implementation schedule to be included in the final report. The integrated schedule will encompass not only the ISAP integrated assessment actions, but also all implementation actions which were not addressed specifically ISAP and all routine licensing actions. The final ISAR will incorporate the requested comments and implementation schedule.

The integrated schedule, developed by the licensee and approved by the NRC, will serve as a stable timetable for the licensee to implement all of the required actions resulting from the ISAP review, as well as those actions not deferred into ISAP, and the routine, foreseeable licensing actions. As such, the licensee will be asked to submit an application for a license amendment to make the integrated schedule plan part of the plant license (see Section 4).

INTEGRATED SAFETY ASSESSMENT REPORT

INTEGRATED SAFETY ASSESSMENT PROGRAM

MILLSTONE NUCLEAR POWER STATION, UNIT NO. 1

1 INTRODUCTION

1.1 Background

In 1977, the U.S. Nuclear Regulatory Commission (NRC) initiated the Systematic Evaluation Program (SEP). Phase I of SEP defined a specific set of safety issues to be reviewed for operating nuclear power plants related to regulatory requirements that had evolved since the majority of operating reactors had been licensed. Phase II of SEP was a pilot review of those issues for eleven of the oldest domestic operating reactors. The results of Phase II of SEP identified significant experience relative to the safety and evaluation techniques for all operating reactors. As originally envisioned, Phase III of SEP was to be the application of Phase II results to all operating reactors.

In 1980, Congress enacted Public Law 96-295 (the NRC Authorization Bill for Fiscal Year 1980). Section 110 of that law required the NRC to develop a program for the systematic safety evaluation of operating reactors. The program proposal would have extended SEP to an evaluation which required licensees to compare their plant design to the acceptance criteria in the Standard Review Plan (SRP, NUREG-0800). Ultimately, that program was not implemented because the proposed scope, as determined by the NRC and Congress, was too broad to efficiently evaluate the safety of operating reactors. However, the development of that scope was useful in that it focused attention on the needs and difficulties associated with the systematic safety evaluation of operating reactors as they relate to a constantly changing technology and increasing number of regulatory requirements.

Following the accident at Three Mile Island Unit No. 2 (TMI-2), the NRC developed the TMI Action Plan (NUREG-0660) from the safety lessons learned. Two aspects of the TMI Action Plan are particularly significant to the evaluation of operating plants: (1) the identification of a large number of corrective actions to be implemented by operating plants and, (2) the initiation of the Interim Reliability Evaluation Program (IREP) in which probabilistic risk assessments (PRA) were conducted for several operating plants.

One of the significant conclusions drawn from SEP and IREP is that issues related to safety of operating nuclear power plants can be more effectively and efficiently implemented in an integrated, plant-specific review. In addition, the experience from SEP has served to focus on the set of current licensing criteria which should be evaluated for operating plants and experience from IREP was to define the methods to conduct a plant-specific probabilistic safety analysis (PSA) which would enhance an integrated safety assessment.

Historically, licensing issues have been evaluated generically and guidelines for any necessary corrective actions have been applied uniformly to all plants. While this approach has provided an effective means to ensure the resolution of these issues, the generic implementation has not given sufficient attention to plant-specific characteristics which have a direct bearing on the appropriateness of the corrective action and the relative importance of an issue in relation to an overall plan for necessary plant improvements. In some cases, alternative corrective actions could be identified which provide an equivalent or greater level of safety, often at less cost to the licensee.

As a result of the experience from these various programs, the NRC developed the regulatory procedures and attendant policies to conduct integrated assessments for operating nuclear power reactors. This approach is called the Integrated Safety Assessment Program (ISAP) and is described in the Commission Policy Statement published in the Federal Register on November 15, 1984 (49 FR 45112).

1.2 Appendix A, ISAP Implementation Plan (Pilot Program)

Due to budget constraints imposed on the NRC, the implementation plan for the ISAP pilot program (see Appendix A) was modified by the staff (details of the plan modification are presented in SECY-85-160 dated May 6, 1985). The pilot program was limited to two operating plants which had already been evaluated in SEP. The modified pilot program was based, at least in part, on the availability of the results of completed or nearly complete plant-specific PSAs and on the minimal effort necessary to update the SEP operating experience reviews. Therefore, the ISAP pilot program for the two operating plants could be finished promptly.

The scope of review would therefore be all pending licensing actions, applicable unresolved safety issues, high priority generic issues and licensee initiated plant improvement projects. However, the review effort concentrates on those topics with a well defined scope and an apparent safety significance to ensure efficiency and a timely completion. Any other issues identified will be addressed broadly in the integrated assessments for completeness.

The staff's review of the licensee's PSA does not involve detailed documentation nor a comprehensive review. Rather, the staff reviewed summary reports prepared by the licensee and only audit selected calculation packages related to dominant contributors as identified in the Millstone Unit No. 1 IREP report and by the licensee, to risk and sensitive analysis methods. The staff relied on the licensee to identify specific plant vulnerabilities to be addressed in the risk perspectives and the assessments for each topic. The staff's review of the PSA is limited such that the staff will not be able to comment on the overall validity or comparability of the PSA and only addresses severe accident alternatives as they relate to the dominant contributors identified by the licensee. This limited PSA review is considered to be adequate given the staff's existing understanding of Millstone Unit No. 1 from the IREP study.

The operating experience evaluations conducted under SEP for these plants are updated and an evaluation performed by the staff to identify significant events or trends that should be addressed in the integrated assessment.

Millstone Nuclear Power Station, Unit No. 1 and the Haddam Neck Plant were volunteered by Northeast Utilities (Northeast Nuclear Energy Company and Connecticut Yankee Atomic Power Company, the licensees, respectively) to participate in the ISAP pilot program. The Integrated Plant Safety Assessment Reports (IPSAR), which concluded the SEP review, were issued in February 1983, and June 1983, for Millstone Unit No. 1 and Haddam Neck, respectively. In addition, Millstone Unit No. 1 was a participant in IREP. The staff report on the risk analysis for the Millstone Unit No. 1 IREP was issued on April 11, 1983. Northeast Utilities stated that new PSAs for both plants were being prepared and would be completed in a timely manner with respect to the ISAP pilot program schedule.

By letter dated May 17, 1985, Northeast Utilities presented the proposed scope of the ISAP pilot program topics for both plants and by letter dated July 31, 1985, the staff concurred with the general scope of the ISAP topics and initiated its ISAP review.

1.3 ISAP Review Methods

1.3.1 Integrated Assessment Team

Once the plant had been selected to participate in ISAP, a dedicated staff review team, the integrated assessment team (IAT), was formed to conduct the ISAP review. The team is made up of an Integrated Assessment Project Manager (IAPM), the Operating Reactor Project Manager (ORPM), the Resident Inspector, a Reliability Analyst and other technical specialists, such as a Human Factors Specialist, as needed. The first responsibility for the IAPM was to organize a site visit to familiarize the IAT with the plant design, site characteristics and licensee organizational structure. A familiarity with the plant is a key prerequisite to the performance of a sound integrated assessment.

1.3.2 Screening Review

The ability to achieve the objectives of the ISAP evaluation depends on a clearly defined scope of review. The topics that ultimately are part of the integrated assessment are derived from a comprehensive listing of all outstanding issues for the specific plant. The sources of issues for the ISAP pilot program include: general licensing actions; unresolved safety/generic issues; licensee initiated plant improvement projects; the results of the review of a plant-specific PSA and plant operating history; Board issues; and pending regulations. Issues resulting from the plant-specific PSA and from the plant operating experience are determined during the course in the ISAP process (refer to Section 1.3.3.) The IAPM initiated the compilation of all outstanding issues and, with the IAT, performed an initial screening of the issues to delete those issues which werenot appropriate for or would not benefit from the ISAP process. The deletion criteria applied by the IAT included, but were not limited to: (1) Issue is of high safety significance that should be implemented immediately; (2) Implementation of issue is by order or equivalent; and (3) Implementation of issue is nearly complete; (4) Issue is a routine and recurring licensing action; (5) Issue is of low safety significance or consequence, and therefore, does not warrant further attention; (6) Issue is not applicable to plant under review; (7) Issue should be combined with other

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with other similar issues; (8) Issue is developmental or confirmatory in nature, not safety significant; (9) Issue has not yet been adequately defined; and (10)Based upon SEP Phase II experience, issue is not amenable to integration.

These issues were deleted from the scope of detailed review in the integrated assessment to ensure effective and efficient resolution; nevertheless, actions taken outside the ISAP scope are still considered where they relate to issues in the scope. Any issue deleted from consideration in ISAP and still open at the time the final integrated assessment is performed will be included in the integrated implementation schedule.

The IAT, at their initial screening review meeting, prepared two lists of issues. The first list contained those issues that the IAT recommended to be considered in ISAP; the second list are those issues that did not pass the initial screening review. At the same time that the NRC developed its list of outstanding issues, the licensee did the same. However, the licensee also included those plant improvement projects that it had initiated. After the separate initial screening reviews, the NRC and the licensee met to make a formal determination of those issues (topics) to be evaluated in ISAP, those issues to be implemented independent of ISAP, and those issues to be deleted from consideration.

The results of the screening review process (topic definitions, scope, review criteria, and justification for continued operation) and the completion schedule proposed by the licensee are subject to NRR division level review and approval. The staff-approved scope of review represented by the topics, in conjunction with the PSA evaluation and updated operating experience evaluation, are sufficiently comprehensive, such that the results of the integrated assessment will provide effective integrated schedules and the basis for future regulatory actions.

1.3.3 ISAP Evaluations

The ISAP evaluation process was divided into three parallel phases: the topic evaluations; performance of a PSA and the subsequent identification of PSA topics; and the evaluation of operating experience and identification of topics.

The ISAP topic evaluations were conducted in a manner similar to that used in SEP Phase II topic evaluations. The licensee prepared a safety analysis for each topic against established review criteria to identify the items to be considered in the integrated assessment. The staff performed a review of these analyses to confirm the completeness of the items to be considered.

The licensee conducted a plant-specific PSA and submitted a PSA summary for staff review. Also, the licensee prepared PSA summaries for those ISAP topics for which risk assessments are amenable. Based upon the review of the licensee's PSA, the staff prepared a safety evaluation to identify the relative strengths and weaknesses in the plant design and operation. The evaluation provides a measure for estimating the potential impact of modifications associated with the items raised in the topic evaluations.

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The operating experience evaluation consists of a collection and evaluation of forced shutdowns and reportable events. The events were generally categorized into levels of relative safety significance by determining cause and effect through an interaction of and by the judgement of the IAT, the plant personnel and licensee's staff. The Systematic Assessment of Licensee Performance (SALP) report prepared periodically by the resident inspector and NRC regional office was also considered in the operating experience evaluation. The resulting staff evaluation of operating experience was issued to the licensee for comment.

In the event that either the licensee or the staff determine, during the course of the PSA/operating experience evaluation review, that an identified scenario or trend warrants prompt corrective action to protect the public health and safety, that action will be pursued expeditiously and independent of ISAP, but will be identified in the Integrated Safety Assessment Report. For example, as a result of its performance of the PSA, NNECO found the issue of long term cooling to be a major contributor to overall plant risk. NNECO identified corrective actions to reduce this risk and implemented them during ISAP. Refer to Section 3.3.80 for further details.

1.3.4 Integrated Assessment

The ISAP topic evaluations, PSA evaluation and operating experience evaluation result in a specific set of issues to be addressed in the integrated assessment. The individual issues were defined in a safety evaluation issued by the staff. The licensee prepares an integrated assessment of the issues and submitted the proposed resolution for staff review. The objective of the integrated assessment is to determine which issues warrant corrective action, based on perceived safety significance, and to develop cost effective actions to resolve multiple issues where practical, to enhance the overall safety of the plant.

The IAT met with the licensee to discuss each of the issues and proposed actions to ensure that each issue is clearly defined and that any pertinent plant-specific design, operation or procedural feature was clearly understood. The review team evaluated the integrated assessment proposal by means of collective judgment of the significance of the issues and the appropriateness of the proposed corrective actions. The judgment was based on both deterministic and probabilistic information developed during the course of the review. The staff's findings and positions are now presented in the form of this draft Integrated Safety Assessment Report (ISAR).

1.3.5 Integrated Safety Assessment Report

The draft ISAR serves as the vehicle to resolve all of the outstanding issues. The draft ISAR is issued for comment to the licensee, the ACRS and peer review experts. In the event that the staff and licensee disagree on the resolution of any given issue, that difference would be aired during the comment period in accordance with established NRC appeal procedures and ultimately presented to the Commission as a policy issue for action, if necessary. The resolution will appear in the final ISAR.

The licensee is also requested to propose an integrated implementation schedule to be included in the final report. The integrated schedule will encompass not only the ISAP integrated assessment actions, but also all implementation actions which were not addressed specifically ISAP and all routine licensing actions. The final ISAR will incorporate the requested comments and implementation schedule.

1.3.6 License Amendments

The ISAR serves as the vehicle to present the resolution of all of the outstanding issues for a plant, as agreed to by the licensee and the staff. The integrated schedule, developed by the licensee and approved by the NRC, will serve as a stable timetable for the licensee to implement all of the required actions resulting from the ISAP review, as well as those actions not deferred into ISAP, and the routine, foreseeable licensing actions. As such, the licensee will be asked to submit an application for a license amendment to make the integrated schedule plan part of the plant license.

The integrated schedule should cover the period during which the ISAP actions will be implemented. During this period any new licensing requirements will be deferred, unless they require prompt action, until the end of the integrated schedule period. At that time, the licensee will update the schedule and submit a new license amendment. The procedures for the updating of the integrated schedule will be included in the integrated schedule plan.

2 MILLSTONE UNIT NO. 1 ISAP REVIEW

2.1 Description of Millstone Unit No. 1

Millstone Unit No. 1, located in New London County, Connecticut, is a boiling water reactor (BWR) designed by General Electric. The licensee is the Northeast Nuclear Energy Company (NNECO). NNECO filed the application for a construction permit and operating license in November 1965. The construction permit was issued in May 1966. The initial submittal of the Final Safety Analysis Report was in March 1968, and the provisional operating license was issued on October 26, 1970. The licensed thermal power rating currently is 2,011 megawatts-thermal (MWt). On September 1, 1972, the licensee applied for a full-term operating license (FTOL).

The 1972 application requested an FTOL at its presently licensed power level for a period of 40 years from May 1966, the issuance date of the construction permit. A complete discussion of the license conversion for Millstone Unit No. 1 is presented in NUREG-1143 and Supplement No. 1 to NUREG-1143. In a letter dated October 31, 1986, the staff issued the FTOL for Millstone Unit No. 1.

The Millstone Unit No. 1 primary coolant system consists of the reactor vessel, recirculation system, main steam system, and isolation condenser. A diagram of the major components of the primary coolant system is provided in Figure 2.1. The reactor is a single-cycle, forced-circulation, boiling water reactor producing steam for direct use in the steam turbine. The reactor vessel contains internal components, which include the necessary equipment for separating the steam and water flow paths.

The recirculation system provides for forced flow through the reactor core to facilitate heat removal capability. The system consists of 2 external loops with motor-driven centrifugal pumps and 20 jet pumps located in the reactor pressure vessel. Water that is separated from the steam in the reactor vessel mixes with water provided by the feedwater system, is drawn from outside the core, passes through the recirculation pumps, and is discharged back into the reactor below the core area at high velocity through the jet pumps. The action of the jet pumps mixes the high velocity water with water in the reactor vessel, recirculating the water through the core. This serves to increase the heat removal capability of the water. The water then flows upward through the core where boiling produces a steam-water mixture.

The main steam system directs the steam generated in the reactor vessel to the turbine generator for conversion to electric power. The steam-water mixture travels from the reactor core, through the steam-separating equipment into the four main steam lines. The steam then passes through the main steam lines to the turbine. Included in the main steam system are the relief and safety valves, which provide overpressure protection for the reactor vessel and associated piping systems. The relief valves are also designed to rapidly depressurize the reactor vessel so that the low-pressure portion of the emergency core cooling systems will function. The reactor safety relief valves are located upstream of the first isolation valve and discharge directly to the pressure-suppression pool.

The isolation condenser system provide reactor core cooling if the reactor should become isolated from the main condenser because of closure of of the main steam isolation valves. The isolation condenser operates by natural circulation. During operation steam flows from the reactor, condenses inside the tubes of the isolation condenser, and flows back to the reactor by gravity. A diagram of the isolation condenser system is provided in Figure 2.2.

The containment systems provide a multibarrier pressure-suppression containment composed of fuel cladding, a primary containment, the pressure-suppression system and a secondary containment, the reactor building.

The primary containment system is designed to (1) provide a barrier that will limit the release of fission products to the secondary containment and (2) rapidly reduce the pressure in the containment resulting from a loss-of-coolant accident. The system consists of a drywell, which houses the reactor vessel and recirculation loops; the pressure-suppression pool, which contains the large volume of water used to condense the accident steam release; and the connecting vent systems. The drywell, which is in the shape of a light bulb and is constructed of steel plate, varies in diameter from 34 ft 2 in. to 64 ft; the spherical section is approximately 64 ft high, and overall the drywell is approximately 100 ft high. The shell thickness varies from approximately 11/16 to 2-3/4 in. The pressure-suppression chamber is a steel pressure vessel in the shape of a torus with an inside diameter of 29 ft 6 in., a water volume of approximately 91,000 cubic feet, and an air volume of approximately 117,000 cubic feet.

The reactor building is designed to provide containment during reactor refueling and maintenance operations when the primary containment system is open. The building will also provide secondary containment when the primary containment is required to be in service. The reactor building consists of the monolithic reinforced concrete floors and walls enclosing the nuclear reactor, primary containment, and reactor auxiliaries, and the building superstructure, which consists of concrete walls and builtup roof decking.

2.2 Millstone Unit No. 1 ISAP Screening Review

By letters dated September 14, 1983, and December 28, 1983, Northeast Utilities requested that Millstone Unit No. 1 and the Haddam Neck Plant participate in an Integrated Safety Assessment Program. Those submittals also provided lists of proposed topics to be evaluated in ISAP. By letter dated April 5, 1984, the staff agreed that these two plants would be good candidates for ISAP. However, the Commission approval for proceeding with the proposed ISAP plan had not yet been received. On November 15, 1984, the Commission Policy Statement on the approved ISAP plan was published in the Federal Register (49 FR 45112, see Appendix A).

Based upon the information submitted by the licensee on September 14 and December 28, 1983, the staff started their initial screening review for the Millstone Unit No. 1 ISAP in early 1985. Starting on April 2, 1985, the staff met with NNECO on several occasions for the purpose of conducting a formal

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screening review. As a result of those meetings, on May 17, 1985, the licensee submitted the formal list of topics to be evaluated in ISAP. Included with each topic was a general description of the topic scope and review criteria.

The staff, in a letter dated July 31, 1985, concluded that the projects identified by the licensee to be performed independent of ISAP for Millstone Unit No. 1 were appropriate (Table 2.1 is a list of these projects). The scope of work to be completed by NNECO during ISAP for these projects, as judged by the staff, constituted a full work load for the NNECO headquarters staff and plant personnel. Also, the staff concurred in the general content of the topics to be evaluated under ISAP. These topics include pending licensing actions listed in NUREG-0748, "Operating Reactor Licensing Actions Summary," for which the staff's review is not yet complete, and licensee initiated plant improvement projects. In addition, the staff identified a number of safety/generic issues, derived from the high priority issues in NUREG-0933, "A Prioritization of Generic Safety Issues," which the staff felt that, although not yet issued for licensee implementation, could be substantially addressed on a plant-specific basis. (Table 2.2 is a list of all ISAP topics).

The staff requested that safety analyses be submitted for each of the ISAP topics. Each safety analysis was to consist of a scope of review along with a concise summary of each topic which addressed the topic's fundamental concern, the applicable review criteria, a deterministic analysis and conclusions. Also, for each topic that was amenable to a PSA evaluation, a PSA topic summary was to be submitted.

2.3 Millstone Unit No. 1 PSA Review Summary

At a meeting in Berlin, Connecticut, on June 3, 1985, Northeast Utilities made a presentation on its application of probabilistic safety assessments to the staff. In that meeting, the licensee stated that it was its intention to perform plant-specific PSAs for all of its plants and to keep those PSAs current. At a minimum, the plant-specific PSAs are to be used by the licensee as a decision-making tool with regard to safety and for evaluating operating plants against corporate safety goals.

The licensee has developed in-house capabilities to perform and maintain their "living" PSAs. Their PSA program was originally tested in the performance of the Millstone Unit No. 3 "Probabilistic Safety Study". The methodology was subsequently applied in performing the Millstone Unit No. 1 PSA and the Haddam Neck PSA. On July 10, 1985, NNECO submitted the "Millstone Unit 1 Probabilistic Safety Study" for staff review. Also, by letters dated from August 13 through November 25, 1985, NNECO submitted the PSA summaries for 21 ISAP topics which were amenable to risk evaluations, as requested in the staff's July 31, 1985 evaluation. The topic PSA summaries were performed by NNECO using one of three methods. The first method was applied to topics for which quantitative risk analyses were directly applicable. The second method used qualitative engineering risk judgements and the last method applied quantitative risk analyses to non-radiological issues.

The NRC contracted with Science Applications International Corporation (SAIC) to review the Millstone Unit No. 1 PSA and summaries of ISAP topic risk evaluations. SAIC had previously been contracted by the NRC to assist the staff in the conduct of the Interim Reliability Evaluation Program and the

Systematic Evaluation Program risk studies, in both of which Millstone Unit No. 1 was a program participant. On September 16, 1985, SAIC completed its draft report "Review of Risk Based Evaluation of Integrated Safety Assessment Program (ISAP) Issues for Millstone Unit 1" (issued by letter dated September 23, 1985). NNECO was requested to review the draft report and provide comments. By letter dated October 21, 1985, NNECO provided comments on the draft report. The staff and SAIC reviewed these comments and on December 31, 1985, issued their final report. This final report was forwarded to NNECO by letter dated January 3, 1986.

The objective of the staff report on the Millstone Unit No. 1 PSA was to identify and resolve significant differences between the IREP and PSA findings, identify areas of plant vulnerability, review those topics which were analyzed in the PSA summaries, and rank the topics with respect to their impact on the safety of the plant.

It is important to note that due to limitations imposed in the ISAP pilot program, the review of the PSA was not performed in the traditional sense of a PRA review. Rather, it was done by comparing the results of each major section of the PSA with the results of the IREP study. Using this comparison, significant differences on the dominant accident sequences and overall core melt frequency were analyzed.

A detailed discussion on the safety studies comparison and the ISAP topic evaluation is found in Appendix C to this report. Further discussion of the PSA evaluation and results are presented in Sections 2.5, "Review of General Topics Scope," and 2.6, "Additional ISAP Topics," as well as in Section 3, "Evaluation of Integrated Assessment Proposal."

2.4 Millstone Unit No. 1 Operating Experience Summary

As part of the SEP review of Millstone Unit No. 1, the plant operating experience through 1981 was evaluated under contract to the NRC by the Nuclear Safety Information Center at Oak Ridge National Laboratory (ORNL). The plant operating experience from January 1 through November 1, 1982, was evaluated by the resident inspector at the Millstone Station. Details of these evaluations are presented in the final SEP IPSAR, NUREG-0824.

For the ISAP evaluation of operating experience, the NRC again contracted ORNL to perform the evaluation. In this case, the review incorporates the evaluation found in the SEP IPSAR and updates that evaluation through 1984. The operating history review focused principally on evaluations of data which is divided into two segments: (1) data on forced shutdowns and power reductions and (2) data on reportable events. In the forced shutdown and power reduction segment, the review identified Design Basis Events (DBE, as defined in the Standard Review Plan, NUREG-0800) and recurring events that may be used as indicators of potential operating concerns. In the reportable event segment, which included environmental events and radiological release events, the review identified significant events and recurring events that may also be used as indicators of potential operating concerns. Selection of significant events was accomplished using a set of criteria established in SEP (see Appendix B).

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By letter dated August 19, 1985, the staff issued the draft operating experience review and requested NNECO to review the report and provide comments. NNECO, by letter dated October 3, 1985, responded to the staff's request for comments. In November 1985, ORNL published the final report on operating experience at Millstone Unit No. 1. The full report is presented in Appendix B to this report and a summary is presented below.

2.4.1 Availability and Capacity Factors

From 1971 through 1984, the cumulative values for reactor availability factor and unit capacity factor at Millstone Unit No. 1 were 78.1% and 73.6% respectively, both of which are above average for commercial nuclear power plants. The reactor availability factor fell below 70% in only two years, 1973 and 1981. The major unit shutdowns in 1973 were for refueling and for feedwater sparger replacement. Combined, these shutdowns accounted for over five months of downtime. In 1981, shutdowns for refueling and for balancing of the turbine because of damage to the 14th low pressure stage which accounted for over five months of downtime.

Of particular note, although outside the scope of this review, is the fact that Millstone Unit No. 1 accomplished 374 consecutive days of operation before shutting down automatically on August 13, 1985.

2.4.2 Forced Shutdowns and Power Reductions

Of the 202 forced shutdowns and power reductions which occurred between 1971 and 1984 at Millstone Unit No. 1, 56 are categorized into 11 types of DBE:

(1) Turbine trip (34 events),
(2) Steam pressure regulator failure resulting in increased steam flow (3 events),
(3) Steam pressure, regulator failure resulting in decreased steam flow (3 events),
(4) Loss of normal feedwater (3 events),
(5) Inadvertent opening of a safety or relief valve (3 events),
(6) Increased feedwater flow (3 events),
(7) Loss of external electric load (2 events),
(8) Inadvertent closure of main steam isolation valve (2 events),
(9) Decreased feedwater temperature (1 event),
(10) Loss of condenser vacuum (1 event), and
(11) Reactor recirculation pump trip (1 event).

49 of these 56 DBEs occurred as a result of equipment failures. Human error caused the remaining seven events. In all DBEs, engineered safety features were reported to operate properly in the mitigation of the transient.

The rate of occurrence of DBEs average about 5 per year over the operating history at Millstone Unit No. 1. The largest number of events in a single year (24) occurred in 1971. There were only two DBEs occurring during the entire period of the last three years covered by the review (1982 through 1984). The frequency of occurrence of each type of DBE is consistent with the experience of other plants, except for turbine trips. Problems with moisture separator drain tank level control during power changes were the primary causes of turbine trips (21 of 34 events). However, the rate of recurrence of these problems decreased with time (14 events per year in 1971, falling to 1 event per year in 1981).

An increase in the rate of recurrence of power reductions since 1980 was caused by the need to locate and repair leaking main condenser tubes. Such leakage results in increased volumes of radioactive waste (radwaste) products generated from the condensate and clean-up system demineralizer. Thus, when it became more difficult to dispose of radwaste products, it was very important to reduce condenser tube leaks. Also, as a side benefit, there was a consequential reduction in occupational exposure to individuals who would otherwise have had to handle and dispose of spent resins.

2.4.3 Reportable Events

A total of 404 reportable events, which occurred at Millstone Unit No. 1 from 1971 through 1984, were reviewed. The rate of generation of event reports over the period under review is generally stable, peaking in the years 1977, 1979, 1981, and 1983, with 38, 36, 44 and 39 events respectively. Inherent equipment failure was reported as the primary cause of 56% of the total number of events. Human error (including administrative, design, fabrication, installation, maintenance, and operator error) was reported as the primary cause of another 43% of this total. Other causes, such as adverse environmental conditions, accounted for the remaining 1%. There is no apparent trend in the causes of reportable events.

Only 13 of the 404 reportable events are classified as significant. These are:

- Loss of the isolation condenser (1 event),
- Loss of provisions for emergency core cooling during a loss of normal power (2 events),
- ECCS failures (2 events),
- Loss of offsite power with partial loss of emergency power (1 event),
- Loss of emergency power (2 events),
- Inadvertent criticality (1 event),
- Replacement of control rod drive accumulators (1 event),
- Recirculation pump trip with no alarm given (1 event),
- Loss of pressure control followed by a blowdown (1 event), and
- Hydrogen explosion in the off-gas system (1 event).

Human error was reported to be the cause of 11 of these 13 events. The remaining 2 events were reported to be caused by equipment failures. All 13 significant events occurred in the years before 1982.

The data shows repeated reports of certain specific operating problems. These recurrences fell principally in eight types of events:

(1) Loss of emergency power supply,
(2) Excessive cooldown,
(3) Pipe crack,
(4) Isolation condenser valve failure,
(5) MSIV failure,
(6) Safety/relief valve setpoint drift,
(7) Stack gas monitor failure, and
(8) Radioactive levels in marine life.

The emergency power system at Millstone Unit No. 1 consists of one diesel generator and one gas turbine generator. If normal power to the plant is lost, the gas turbine is the sole power source for the Feedwater Coolant Injection (FWCI) system. The gas turbine generator failed to start or run for its entire mission 37 times. Many of these failures occurred when redundant power systems or systems redundant to the FWCI system were not operable.

Five excessive thermal transients in eight blowdowns were experienced resulting from failures of safety and relief valves. The cooldown rates during the transients ranged from 105°F/h to 450°F/h. The first of these events occurred in 1971. Between 1975 and 1981 the transients occurred at a rate of about one every two years. There were no recurrences after 1981.

Ten instances of pipe cracks were reported. Cracks appeared in feedwater spargers, core spray piping, main steam line supports, and condenser nozzles. Pipe cracking found at Millstone Unit No. 1 is typical of the generic problems found in many BWRs.

A variety of problems caused twelve failures of the isolation condenser valves between 1970 and 1984. In seven of the twelve events, a supply valve either opened too wide or failed to open, which caused the isolation condenser system to fail. On one occasion a valve transferred open causing an isolation condenser system failure. On another occasion, a valve transferred open and initiated the isolation condenser system. Another event occurred because a return valve failed to close. Three isolation valve failures occurred, two of which were due to limit switch problems.

There were eight occurrences of failure of Main Steam Isolation Valves (MSIVs). The predominant cause for MSIV failures involved a poor quality of control-air supplies to the pilot valves. This failure mechanism has the potential to affect more than one MSIV at a time. All MSIV related failures occurred prior to 1981.

There were two events involving set point drift in safety/relief valves. A total of six valves were affected. This is a generic problem for BWRs.

On two occasions in 1982, a loss of the stack gas monitor was experienced resulting from operator error. A design change was made to include both a timer and an alarm for the monitor to prevent recurrences of this problem. No events involving the stack gas monitor were reported after 1982.

Nine reports of finding higher than allowed levels of radioactive silver and cobalt in marine life were submitted during the period from 1981 through 1984. The majority of occurrences were in 1982, and in 1983. The utility concluded from calculations of the dose consequences that the doses were insignificant and that the reporting requirements are overly conservative.

2.4.4 Plant Visit

As part of the review effort, the ISAP integrated assessment team visited the plant. Valuable insights were gained from discussions with plant personnel and from a tour of the Millstone site facilities. Knowledgeable plant personnel answered questions that arose from the review analysis. Visual inspections of the general plant conditions, the state of operating equipment and the areas where problems in operations had been experienced provided additional perspective to the team for their evaluations.

2.4.5 Conclusions

The findings of this review do not lead to any conclusion that there are continuing major challenges to plant safety inherent in the operations of Millstone Unit No. 1. As evidenced by the record of the plant's availability and capacity factors over the period of the review, and the relatively small number of significant reportable events, the operational record of Millstone Unit No. 1 can be judged to be better than average.

Nevertheless, a number of problems are identified from the data. Significant recurring problems are evident in eight discrete areas. Examination of the data shows that the recurrence of two of these eight areas, failures in the stack gas monitor and high cooldown rates, has ceased. In one area involving reports of radioactivity levels in marine life that were higher than allowed, the problem was found to lie in overly conservative reporting requirements, and has been alleviated through technical specification changes. However, the other five problem areas remain as outstanding concerns. These five are:

(1) Loss of emergency power supply capabilities,
(2) Pipe cracks,
(3) Isolation condenser valve failures,
(4) MSIV failures, and
(5) Safety/relief valve setpoint drift.

The data shows that the majority of the operating experience problems were confined to random events, reflecting much of the experience of other operating BWRs. No other significant problems are identified through trends or patterns in the data.

These conclusions are discussed in detail in Appendix B of this report and in Section 2.6, "Additional ISAP Topics."

2.5 Review of General Scope of Topics

As requested in our July 31, 1985, letter to NNECO, the licensee, by letters dated August 13 through November 25, 1985, submitted ISAP topic summaries for review. In addition, supplemental information was submitted for several of the topics in letters dated through February 4, 1986.

The staff reviewed each of the topic submittals to determine if the content of the detailed topic scope was appropriate and to determine if any of the topics, based upon the information submitted, were resolved. The conclusions reached by the staff in their review of the topics scope and summaries can be categorized as one of the following:

(1) The staff concurs that the issues identified with respect to the topic scope are appropriate for consideration in the integrated assessment;
(2) The staff has redefined the scope of the topic to reflect additional considerations;
(3) The staff has developed a new topic for consideration in the integrated assessment. (This item is discussed in more detail in the following section.)
(4) The scope of the topic has been resolved and, therefore, does not need to be evaluated in the integrated assessment.

By letter dated March 3, 1986, the staff issued the results of this review. Table 2.2 summarizes the results of the staff's review of the topic summaries.

2.6 Additional Topics Considered in the Integrated Assessment

The staff's review of the Millstone Unit No. 1 PSA identified four areas where individual contributors to plant risk are significant and may warrant further evaluation. These areas are: (1) Isolation Condenser failure to start (8E-5 per year CMF); (2) Isolation Condenser makeup failure (2.8E-4 per year CMF); (3) failure to restore Main Condenser (1E-4 per year CMF); and (4) operating experience review identification of MSIV failures.

The staff evaluation of the Millstone Unit No. 1 operating experience through 1984 concluded that there are no continuing major challenges to plant safety inherent in the operations of the plant. The operating data shows that the majority of the operating experience problems were confined to random events. However as noted in Section 2.4.5, significant recurring problems were noted in five areas: (1) loss of emergency power supply capabilities; (2) pipe cracks; (3) isolation condenser valve failures; (4) MSIV failures; and (5) safety/relief valve setpoint drift.

Item (1) from the operating experience review concerns the availability of the gas turbine generator (GTG). It was found that no single component failure or operational problem dominated the independence of the GTG. Most of the problems were identified during the monthly tests and not during actual demand. The consequences of the failure of the GTG to operate on demand is a degradation of the ECCS because onsite power for the FWCI is provided by the GTG only. This item is being addressed in ISAP Topics 1.01 and 1.24. Also, during the 1985 refueling outage NNECO implemented GTG electrical equipment protection modifications. Therefore, the staff concludes that Item (1) from the operating experience review is adequately addressed in ISAP and no additional topic was necessary to resolve this item.

Item (2) from the operational experience review concerns the continuing problem of pipe cracks due to Intergranular Stress Corrosion Cracking (IGSCC) at BWRs. Item 18 in the staff's July 31, 1985 letter for actions that are to be conducted independently of ISAP, directly addresses IGSCC at Millstone Unit No. 1. Also, by letter dated July 1, 1985, the licensee presented the inspection and IGSCC mitigation history at Millstone Unit No. 1, as well as the basis for the planned inservice inspection during the 1985 refueling outage. On the basis of the information presented by the licensee, the staff concluded in its letter of December 6, 1985 that the IGSCC inspection plan and inspection results adequately support the return of Millstone Unit No. 1 to full power for its next 18-month fuel-cycle. Therefore, the staff concludes that Item (2) from the operating experience review is a routine licensing activity and is being adequately addressed outside of ISAP such that no additional topic evaluation is necessary to resolve this item.

Item (3) from the operating experience review concerns isolation condenser failures from improper functioning of the isolation condenser valves. Millstone Unit No. 1 experienced 12 failures of these valves from 1970 through 1984. These failures had a small affect on the operation of the isolation condenser,

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but did affect the ability to isolate the containment. The staff concludes that, given the importance of the function of the isolation condenser and the containment, the licensee should evaluate this issue in the integrated assessment.

Item (4) from the operating experience review is concerned with the failure of the main steam isolation valves. The problems with MSIVs that occurred during the early years of plant operation involved sticking of the air-slide valves. Modifications were implemented by the licensee that improved the quality of the air supply to the valves. Also, a program of testing and maintenance was implemented. These problems appear to have been resolved. Problems with the MSIVs in recent years primarily involved failures of the limit switches. All MSIV limit switches were recently replaced with environmentally qualified switches and this may resolve this problem. Also, ISAPs Topic 2.23 and 2.30 address service air quality and MSIV closure test frequency. The staff concludes that the concerns in Item (4) of the operating experience review have either been adequately resolved or will be resolved by existing ISAP topics so that no additional topic evaluation is necessary.

Item (5) from the operating experience review is concerned with setpoint drift in safety/relief valves. Three events involving safety/relief valves were identified. In 1977 a safety/relief valve inadvertently opened for no known reason. The other two events were due to setpoint drift. This is a generic problem for BWRs and the BWR Owners Group is currently evaluating this problem. The staff concludes that, given the importance of the function of the safety/relief valves, the licensee should evaluate short term actions, in the integrated assessment, that could be taken until the generic resolution to this problem is available.

Therefore, based upon PSA and operating experience review results, the staff concluded that NNECO should evaluate the following additional topics in the integrated assessment by refined PRA methods or deterministic means to see if cost-beneficial solutions to reduced plant risk can be achieved.

Topic 1.50 - Isolation Condenser startup/makeup failures
1.51 - Failure to restore Main Condenser
1.52 - Safety/Relief valve failure/setpoint drift

In addition to the three additional ISAP topics identified by the staff, NNECO, in a letter dated July 31, 1985, identified two additional plant improvement projects that they wished to evaluate in ISAP. These topics are:

Topic 2.32 - Primary Containment Pump-Back System
2.33 - RBCCW Leak Rate Testing

A short description of the scope of the integrated assessment for each of the three additional staff identified topics follows. Detailed descriptions of all 85 topics, their proposed resolutions and relative implementation priority are are presented in Sections 3 and 4 of this report.

2.6.1 Topic 1.50, Isolation Condenser Startup/Makeup Failures

The Millstone Unit No. 1 PSA determined that isolation condenser makeup failures and initiation/startup failures appear in 11 of the 18 dominant sequences. The PSA further indicates that the makeup failures are dominated by a motor operated valve (MOV) which fails to open and by failure of the two diverse fire water supply pumps. The initiation/restoration failures are dominated by contact pair failure and failure of motor operated valve 1-IC-3 to open. The licensee should evaluate, by plant-specific probabilistic analyses or by mechanistic analysis, potential improvements to the isolation condenser to improve its availability/reliability.

2.6.2 Topic 1.51, Failure to Restore Main Condenser

The Millstone Unit No. 1 PSA determined that failure to restore the main condenser contributes to sequences estimated to have a core melt frequency of about 1E-4 per year. The licensee should evaluate methods whereby the capability to restore the main condenser could be improved.

2.6.3 Topic 1.52, Safety/Relief Valve Failure-Setpoint Drift

The Millstone Unit No. 1 PSA identified that failure of the safety/relief valves to close contributes to sequences estimated to have a core melt frequency of about 1E-4 per year. In addition, the Millstone Unit No. 1 operating experience review identified a general problem of BWR safety/relief valve setpoint drift. The licensee should evaluate methods whereby the safety/relief valves reliability can be improved.

2.7 Status of ISAP Topics

The staff, in a letter dated July 31, 1985, approved a list of projects that the licensee was to implement independent of the ISAP pilot program. Those projects include: (1) plant modifications and procedural changes that are ready for implementation during the next outage (fall 1985) or before the scheduled completion of ISAP and/or significant safety improvements that should not be delayed, and (2) ongoing engineering studies and plant modification design efforts that have a well defined objective and would not likely be enhanced by an integrated assessment. The list of these projects is presented in Table 2.1.

Also in the staff's letter of July 31, 1985, the staff approved the general scope of the 80 topics to be evaluated in the Millstone Unit No. 1 ISAP. Subsequently, in a letter dated March 3, 1986, the staff approved the specific scope of the original 80 topics and identified three additional topics, based upon the staff's review of the Millstone Unit No. 1 PSA and plant operating experience summaries. Also, by the time of the staff's March 3, 1986 letter, the licensee and the staff identified a number of topics which had either been cancelled or completed. As such, these topics, if their completion did not result in additional implementation projects, do not have to be addressed in the integrated assessment. Table 2.2 presents the status of the 85 Millstone Unit No. 1 ISAP topics (including two additional topics proposed by NNECO) as identified in the March 3, 1986 letter. For those topics indicated as being complete or cancelled in Table 2.2, a brief justification for this status is presented in Section 3 of this report. The current status, based upon the results of the integrated assessment evaluation, of the remaining topics is also presented in Section 3.

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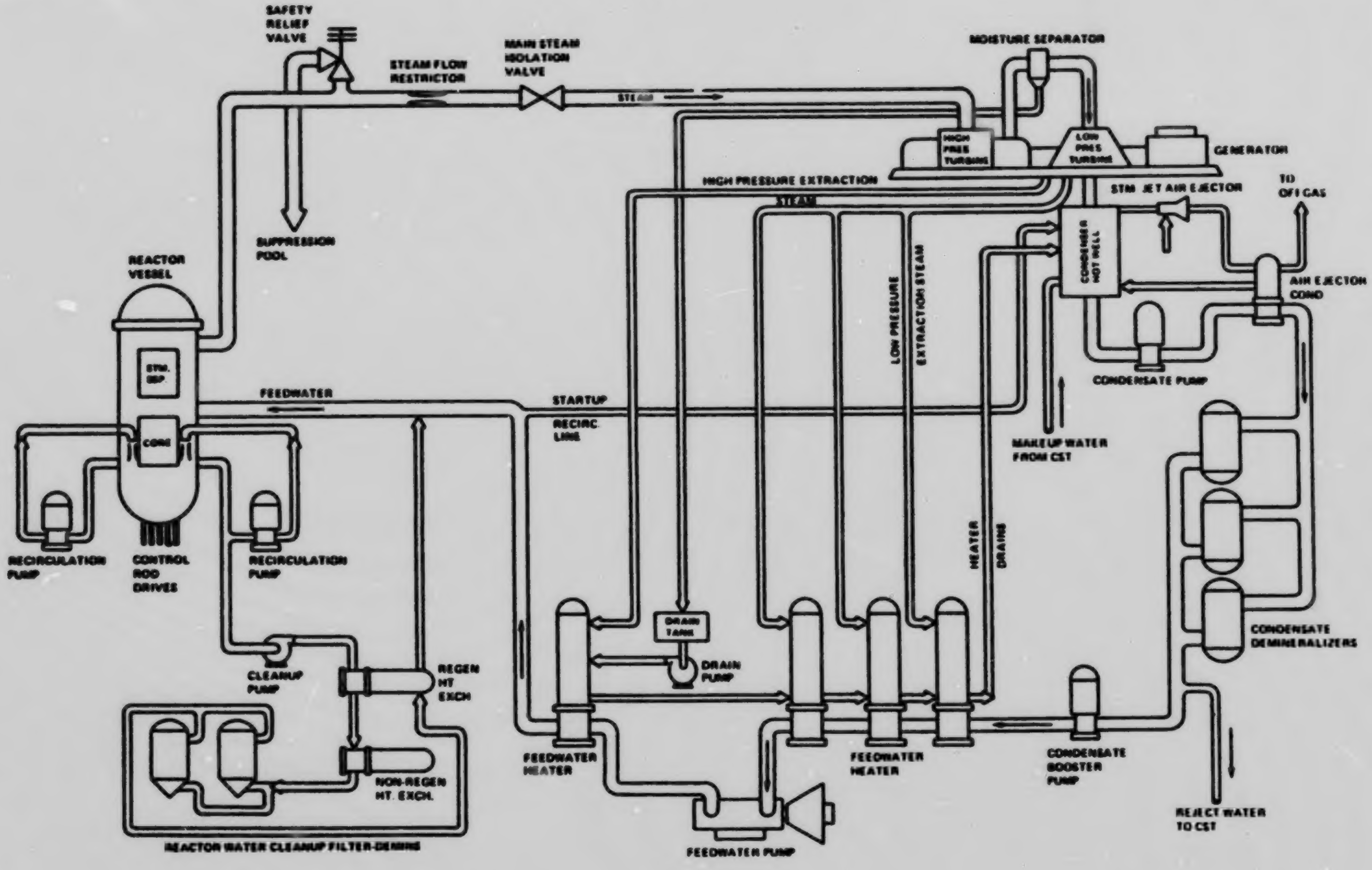
Copies of this report and the associated safety evaluation reports referenced in Section 3.3 for the 85 ISAP topics are available for public inspection at the NRC Public Document Room, 1717 H Street, N.W., Washington, D.C. 20555 and at the Waterford Public Library, Rope Ferry Road, Route 156, Waterford, CT 06385.

Additional information may be obtained from:

M. L. Boyle, Integrated Assessment Project Manager
Division of PWR Licensing - B
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
(301) 492-7636


SAFETY
RELIEF
VALVE
STEAM FLOW
RESTRICTOR
MAIN STEAM
ISOLATION
VALVE
STEAM
MOISTURE SEPARATOR
HIGH
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LOW
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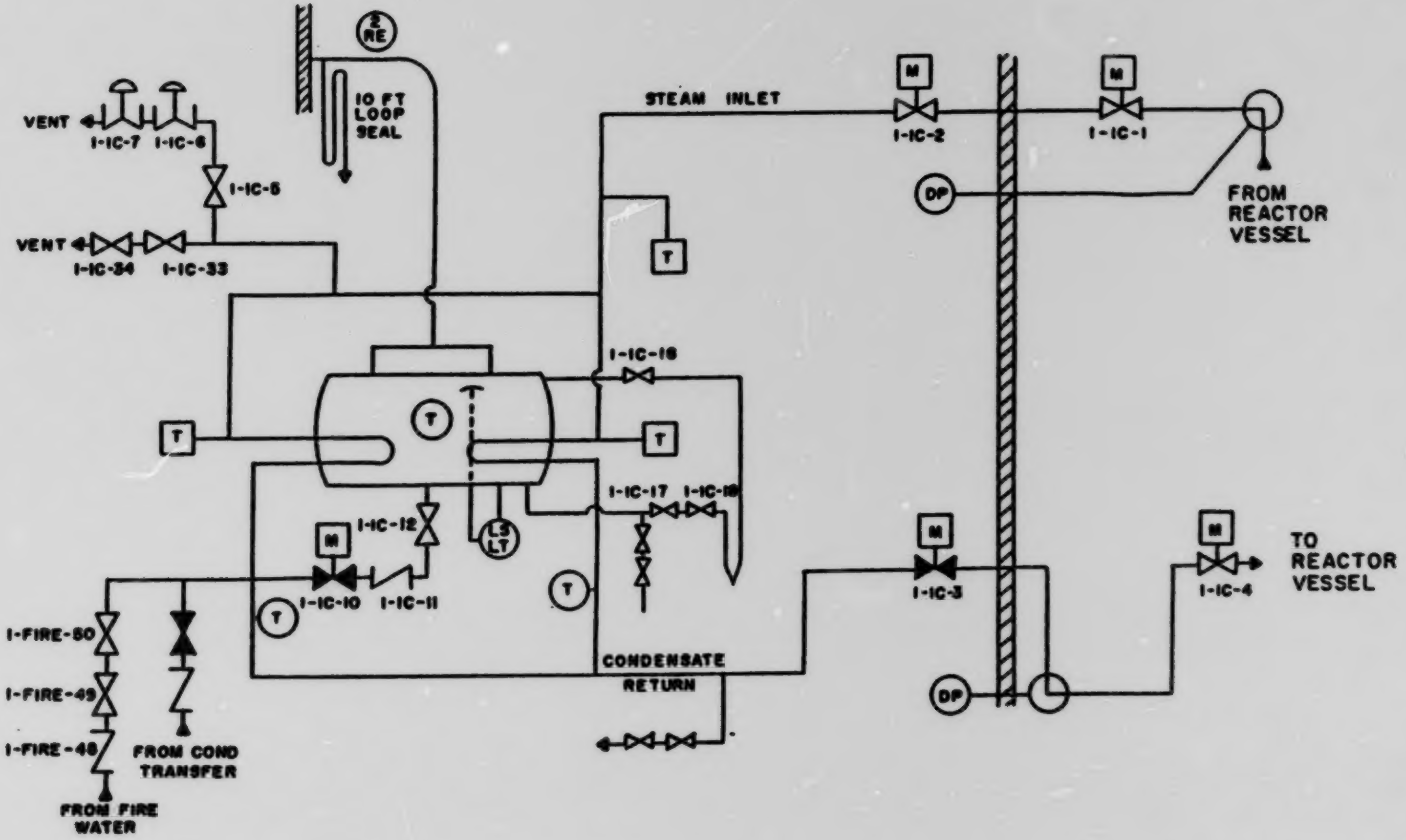
TURBINE
GENERATOR
HIGH PRESSURE EXTRACTION
STEAM
STM JET AIR EJECTOR
TO
OFFGAS
SUPPRESSION
POOL
REACTOR
VESSEL
STM.
SEP.
CONDENSER
HOT WELL
AIR EJECTOR
COND
LOW PRESSURE
EXTRACTION STEAM
CONDENSATE PUMP
FEEDWATER
STARTUP
RECIRC.
LINE
CORE
MAKEUP WATER
FROM CST
RECIRCULATION
PUMP
CONTROL
ROD
DRIVES
RECIRCULATION
PUMP
HEATER
DRAINS
DRAIN
TANK
DRAIN
PUMP
CONDENSATE
DEMINERALIZERS
CLEANUP
PUMP
REGEN
HT
EXCH
FEEDWATER
HEATER
FEEDWATER
HEATER
CONDENSATE
BOOSTER
PUMP
NON-REGEN
HT. EXCH.
REJECT WATER
TO CST
REACTOR WATER CLEANUP FILTER-DEMINS
FEEDWATER PUMP

Figure 2.1 Millstone Nuclear Generating Station, Unit 1 -- primary coolant system


VENT
I-IC-7
I-IC-6
I-IC-5
VENT
I-IC-34
I-IC-33
2 RE
10 FT LOOP SEAL
STEAM INLET
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I-IC-2
M
I-IC-1
DP
FROM REACTOR VESSEL
T
I-IC-16
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I-IC-18
M
I-IC-12
LS LT
I-IC-10
I-IC-11
T
T
M
I-IC-3
M
I-IC-4
TO REACTOR VESSEL
I-FIRE-50
I-FIRE-49
I-FIRE-48
FROM COND TRANSFER
FROM FIRE WATER
CONDENSATE RETURN
DP

Figure 2.2 Millstone Nuclear Generating Station, Unit 1
Isolation Condenser System

Item #	Project
1	Seismic Qualification of Safety Related Piping
2	Primary Containment Leak Rate Monitoring
3	Undervoltage Protection Emergency Bus
4	Replacement of Motor Operated Valves
5	Floodgate Mods. and Installation of Scuppers
6	Refueling Cavity Seal Evaluation
7	Records Vault Temperature and Humidity Control
8	Process Computer UPS Installation
9	MS Relief Valve Vacuum Breaker Load Qualification
10	Station Battery "A" Replacement
11	Rev. and Eval. for Diesel Air Start System
12	Gas Turbine Generator Elec. Equipment Protection
13	Auxiliary Equipment System Ocillograph
14	Supervisory and Events Recorder Systems
15	Replace Main Generator Neutral Grounding Trans.
16	Limitorque Motor Operated Valves:Lubrication
17	460V Motor Soft Start Capability
18	IGSCC Countermeasures
19	Circulating Water Piping Thrust Block Repairs
20	Gas Turbine Generator Battery Replacement
21	Solid Radwaste Building Ventilation and Roof Mods.
22	Spent Fuel Pool Cleanup
23	Voltage Regulator, Instrument Trans Replacements
24	House Heating Boiler Stack
25	Procuring Nucl. Grade Mat./Service Sensitive Lines
26	Plant Training Simulator
27	Probabilistic Safety Study
28	Unit Availability Model
29	Roof Replacement
30	Emer. Gas Turbine Generator Vibration Switches
31*	Containment Ventilation Coolers
32*	Gas Turbine Rotor Replacement

* Projects not appearing in July 31, 1985 letter.

Table 2.1 Millstone Unit No. 1
Items to be Implemented Independent of ISAP

ISAP Topic #	Title - NRC Initiated Topics	Issue Source	PSS Summary	ISAR Category*	ISAR Section #
1.01	Gas Turbine Generator Start Logic Modifications	SEP Topic VIII-2	Yes	1	3.3.1
1.02	Tornado Missile Protection	SEP Topic III-4.A	Yes	1	3.3.2
1.03	Containment Isolation-Appendix A Modifications	SEP Topic VI-4		1	3.3.3
1.04	RWCU System Pressure Interlock	SEP Topic V-11.A	Yes	1	3.3.4
1.05	Ventilation System Modifications	SEP Topic IX-5	Yes	1	3.3.5
1.06	Seismic Qualification of Safety Related Piping	IEB 79-02&-14	Yes	1	3.3.6
1.07	Control Room Design Review	NUREG-0737:Suppl 1	Yes	1	3.3.7
1.08	Safety Parameter Display System	NUREG-0737:Suppl 1		1	3.3.8
1.09	RG 1.97 Instrumentation	NUREG-0737:Suppl 1		1	3.3.9
1.10	Emergency Response Facilities Instrumentation	NUREG-0737:Suppl 1		1	3.3.10
1.11	Post Accident Hydrogen Monitor	NUREG-0737:Suppl 1		1	3.3.11
1.12	Control Room Habitability	NUREG-0737:III.D.3.4		1	3.3.12
1.13	BWR Vessel Water Level Instrumentation	NUREG-0737:II.F.2	Yes	1	3.3.13
1.14	Appendix J Modifications	10CFR50	Yes	1	3.3.14
1.15	FSAR Update	10CFR50.71		4	3.3.15
1.16	Appendix R	10CFR50.48	Yes	1	3.3.16
1.17	Replacement of Motor Operated Valves	10CFR50.49	Yes	2	3.3.17
1.18	ATWS	10CFR50.62	Yes	1	3.3.18
1.19	Integrated Structural Anaysis	Various SEP Topics		1	3.3.19
1.20	MOV Interlocks	SEP Topic III-10.A	Yes	4	3.3.20
1.21	Fault Transfers	SEP Topic VI-7.C.1		1	3.3.21
1.22	Electrical Isolation	SEP Topic VII-1.A		1	3.3.22
1.23	Grid Separation Procedures	SEP Topic VIII-1.A		4	3.3.23
1.24	Emergency Power	SEP VIII-2	Yes	4	3.3.24
1.25	Degraded Grid Voltage Procedures	MPA B-23		2	3.3.25
1.26	Item 2.1-Equipment Classification/Vendor Inter.	Salem ATWS GL 83-28		1	3.3.26
1.27	Items 3.1.1&.2-Post Maintenance Testing	Salem ATWS GL 83-28		1	3.3.27
1.28	Item 3.1.3-Post Maintenance Testing TS Changes	Salem ATWS GL 83-28		4	3.3.28
1.29	Response to GL 81-34	MPA B-65		4	3.3.29
1.30	Item 1.2-Post Trip Review Data and Information	Salem ATWS GL 83-28		1	3.3.30
1.31	Item 2.2-Equipment Classification/Vendor Inter.	Salem ATWS GL 83-28		1	3.3.31
1.32	Items 3.2.1&.2-Post Maint. Testing Procedures	Salem ATWS GL 83-28		4	3.3.32
1.33	Item 3.2.3-Post Maintenance Testing TS Changes	Salem ATWS GL 83-28		4	3.3.33
1.34	Items 4.5.2&.3-Reactor Trip System Testing	Salem ATWS GL 83-28		1	3.3.34
1.35	Item 4.5.1-Reactor System Functional Testing	Salem ATWS GL 83-28		4	3.3.35
1.36	TS Covered by GL 83-36	MPA B-83		1	3.3.36
1.37	TS Affected by 50.72 and .73 (GL 83-43)	MPA A-18		4	3.3.37
1.38	Expand QA List	NUREG-0933		4	3.3.38
1.39	Radiation Protection Plans	NUREG-0933		4	3.3.39
1.40	Bolting Degradation or Failure	NUREG-0933		2	3.3.40
1.41	Flooding of Compartments by Backflow	NUREG-0933		4	3.3.41
1.42	MSL Leakage Control Systems	NUREG-0933		4	3.3.42
1.43	Water Hammer	NUREG-0933		4	3.3.43
1.44	Asymmetric Blowdown Loads on Reactor Systems	NUREG-0933		4	3.3.44
1.45	Systems Interaction	NUREG-0933		1	3.3.45

Table 2.2 Millstone Unit No. 1 ISAP Topics

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ISAP Topic #	Title - NRC Initiated Topics	Issue Source	PSS Summary	ISAR Category*	ISAR Section #
1.46	Determination of SRV Pool Dynamic Loads	NUREG-0933		4	3.3.46
1.47	Containment Emergency Sump Performance	NUREG-0933		2	3.3.47
1.48	Safety Factor for Penetration X-10A	Oper. Exp.		1	3.3.48
1.49	Reactor Vessel Surveillance Program	10CFR50 App. G & H		4	3.3.49
1.50	Isolation Condenser Startup/Makeup Failures	PSS/Oper. Exp. Rev.		3	3.3.50
1.51	Failure to Restore Main Condenser	PSS/Oper. Exp. Rev.		3	3.3.51
1.52	Safety/Relief Valve Failure/Setpoint Drift	PSS/Oper. Exp. Rev.		3	3.3.52

ISAP Topic #	Title - NU Initiated Topics	Issue Source	PSS Summary	ISAR Category*	ISAR Section #
2.01	LPCI Remotely Operated Valve 1-LP-50A&B	NU	Yes	1	3.3.53
2.02	Drywell Humidity Instrumentation	NU		1	3.3.54
2.03	Process Computer Replacement	NU		1	3.3.55
2.04	High Steam Flow Setpoint Increase	NU	Yes	1	3.3.56
2.05	Hydrogen Water Chemistry Study	NU		1	3.3.57
2.06	Condenser Retube	NU	Yes	1	3.3.58
2.07	Sodium Hypochlorite System	NU	Yes	1	3.3.59
2.08	Extraction Steam Piping	NU	Yes	1	3.3.60
2.09	Upgrading of Piping and Instrumentation Diagrams	NU		2	3.3.61
2.10	Drywell Ventilation System	NU		1	3.3.62
2.11	Stud Tensioners	NU		1	3.3.63
2.12	Reactor Vessel Head Stand Relocation	NU		1	3.3.64
2.13	Turbine Water Induction Modifications	NU		4	3.3.65
2.14	Evaluation and Implementation of NUREG-0577	NU		4	3.3.66
2.15	Torque Switch Evaluation for MOVs	NU		1	3.3.67
2.16	Reactor Protection Trip System	NU		1	3.3.68
2.17	4.16kV, 480V & 125Vdc Plant Distribution Prot.	NU		1	3.3.69
2.18	Spent Fuel Pool Storage Racks/Transporation Cask	NU		1	3.3.70
2.19	DC System Review	NU		4	3.3.71
2.20	RWCU System Isolation Setpoint Reduction	NU		1	3.3.72
2.21	480V Load Center Repl. of Oil Filled Breaker	NU		1	3.3.73
2.22	Control Rod Drive System Water Hammer Analysis	NU		4	3.3.74
2.23	Instrument, Service and Breathing Air Imprvs	NU		1	3.3.75
2.24	Offsite Power Systems	NU		1	3.3.76
2.25	Drywell Temperature Monitoring System Upgrade	NU		1	3.3.77
2.26	Reliability Equipment	NU		1	3.3.78
2.27	Spare Recirculation Pump Motor	NU		1	3.3.79
2.28	Long Term Cooling Study	NU	Yes	1	3.3.80
2.29	FWCI Assessment Study	NU		1	3.3.81
2.30	MSIV Closure Test Frequency	NU	Yes	1	3.3.82
2.31	LPCI Lube Oil Cooler Test Frequency	NU	Yes	1	3.3.83
2.32	Primary Containment Pump-Back System	NU		3	3.3.84
2.33	RBCCW Leak Rate Testing	NU		3	3.3.85

*ISAR Category: 1 - Topic OK for Integrated Assessment
2 - Topic redefined for Integrated Assessment
3 - Additional topic
4 - Topic resolved/cancelled

Table 2.2 Millstone Unit No. 1 ISAP Topics (Cont.)

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3 EVALUATION OF THE INTEGRATED ASSESSMENT PROPOSAL

3.1 Introduction

In a letter dated May 17, 1985, NNECO outlined a proposal for the conduct of ISAP for Millstone Unit No. 1. The staff in a letter dated July 31, 1985, concluded that the projects identified in NNECO's proposal were appropriate to be included in an integrated assessment. Also, in that letter, the staff requested that a safety analysis summary and a PSA summary, as appropriate, for each topic be submitted for our review. In letters dated August 13 through November 25, 1985, the requested analyses and PSA summaries were submitted. Also, additional information for several of the topics was submitted through February 4, 1986.

In the letter dated July 31, 1986, NNECO submitted the integrated assessment proposal for Millstone Unit No. 1. The objective of that proposal was to make a decision, based upon topic safety analysis, PSA summary and a prioritization methodology, as to which topics warrant further action and which do not.

In the July 31, 1986, letter, NNECO proposed a prioritization process to determine relative priorities for implementation of the proposed modifications or projects. NNECO's prioritization process was implemented in four steps, which are summarized below.

(1) Define Attributes - These are separate benefit dimensions which are considered during project evaluation. They are selected to reflect overall corporate objectives for the nuclear program and are approved by senior management.

(2) Score and Evaluate Projects - Independent teams comprised of experienced personnel score all projects for each attribute (one team per attribute). The ISAP Working Group, a group which consists of personnel from the various disciplines within the Northeast Utilities organization (i.e., Engineering, Plant, Project Management, etc.), then meets as a task force to evaluate each project and review the scoring basis for each attribute. Both the project scope and the individual scores are evaluated by the Working Group to assure the expected benefit-to-cost ratios are based upon a consistently applied understanding of each project. Interchanges among the scoring teams at the Working Group meetings serve to develop broad organizational perspectives and consensus on each project's value.

(3) Consolidate Scores and Rank Projects - Separate scores for each attribute are converted to common units and summed (or integrated) to obtain a meaningful overall benefit score for each project. As part of the summation methodology, weighting factors were developed and are applied to reflect management's judgement on the appropriate relative emphasis for each attribute, consistent with their direction for NU's nuclear program. The implementation cost is determined for each project and an overall benefit-to-cost ranking is produced.

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(4) Finalize Rankings - Sensitivity and verification tests are performed to ensure that the rankings are logical and consistent with NU's corporate values. Adjustments to score are permitted based on objective reevaluation of selected projects. The final priorities are approved by NU's senior management.

In order to determine the "value" of a proposed plant modification, NU has developed a set of attributes against which projects are evaluated. These attributes were chosen in order to provide a broad perspective on the merits of potential plant improvement projects. The five attribute impact models that are utilized in the ranking methodology for the Millstone Units No. 1 ISAP topics are: public safety, personnel safety, economic performance, personnel productivity, and external impacts.

Each of the attributes encompasses multiple characteristics and/or components. The personnel safety attribute, for example, includes both industrial safety and radiation safety components; the economic performance attribute includes separate components for availability, reliability and maintainability impacts.

As the first step in the development of these attribute definitions, a tentative set of attributes was defined considering approaches used by various other utilities for their Integrated Implemenation Schedule (IIS) programs. The proposed attribute set was reviewed for consistency with NU corporate policies, goals and objectives. Later, the attributes were reviewed by the ISAP Working Group. Finally, the five selected attributes were also presented to NU management for review and were approved for the ISAP program.

The five selected attributes for the ISAP prioritization process are described as follows:

(1) Public Safety - This attribute captures the NU commitment to safe operation of its nuclear facilities by limiting the incremental risk to the public to an acceptably low level. The public safety attribute includes the characteristics of:

- radioactive material release from the plant;
- hazardous material (non-radioactive) releases from plant; and
- hazards from transportation accidents offsite

The impacts of this attribute are determined utilizing PRA results where applicable in conjunction with subjective judgement.

(2) Personnel Safety - This attribute captures the NU commitment to ensuring the safety of on-site personnel. The personnel safety attribute includes the characteristics of:

- occupational radiation exposure; and
- industrial safety.

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The impacts of this attribute are determined using a combination of quantitative and qualitative factors, including dollar value per man-rem, cost per lost workday, and potential company liabilities.

(3) Economic Performance - This attribute captures the NU objective of furnishing reliable and economical power to their customers. The economic performance attribute includes the characterisitcs of:

- effects on plant availability;
- effects on plant efficiency;
- effects on electrical output; and
- effects on core power rating.

The impact of this attribute are determined utilizing plant-specific reliability/availability/maintainability (RAM) models where applicable, combined with subjective judgement and assessment of future risks or benefits.

(4) Personnel Productivity - This attribute captures the NU commitment to maintain an organizational culture conducive to high quality work with good productivity. The personnel productivity attribute includes the characteristics of:

- effects on people;
- effects on equipment; and
- effects on work environment.

The impacts of this attribute are determined by subjective judgement supplemented by qualitative data where available, and include effects of changes in equipment or procedures on personnel efficiency, effects of training on productivity, and effects of physical stress and work environment on productivity.

(5) External Impacts - This attribute captures the NU commitment to operate its power plants within regulations and with due consideration of external influences. The external impacts attribute includes the characteristics of:

- NRC actions;
- actions of state/local governments and agencies
- actions of other federal regulatory agencies; and
- actions of industry organizations.

The impacts of this attribute are determined by subjective assessment of the risks associated with not performing a project and the potential for forced shutdown.

3.2 1985 Refueling Outage Projects and Activities

As discussed in Section 2 of this report, part of the basis for deferring action on outstanding licensing actions at Millstone Unit No. 1 to develop an integrated schedule for those actions was the maintenance of an appropriate work load for both the engineering and operations personnel. During the period that NNECO has been developing their ISAP topic resolutions and PRA review, NNECO has continued to work on engineering evaluations and plant modifications, either required by the NRC or initiated by NNECO.

Listed below are significant projects completed during the 1985 Millstone Unit No. 1 refueling outage.

(1) Seismic Hanger Modifications

Modifications were completed on 77 supports out of a total of 130 supports available to be worked. In addition, modifications were completed on 44 supports prior to the outage. The remaining 300 piping supports, out of an original 1100 support modifications, have been evaluated and the modifications prioritized (See Section 3.3.6)

(2) Replacement of Motor Operator Valves

This project consisted of the replacement of the motor operators and some work on valve internals on a total of seven motor operated valves (MOVs). The valves worked were 1-IC-3, 1-LP-7A and 7B, 1-LP-10A and 10B, and 1-CS-5A and 5B. A torque switch for valve motor operator on SW-9 was also replaced for environmental qualification purposes. The remaining 11 valve operators that are required to be environmentally qualified, have been evaluated and prioritized (See Section 3.3.17).

(3) Drywell Ventilation

The goal of this project was to replace as many drywell cooling units as possible without impacting the outage critical path schedule. Replacement of five coils was targeted as the minimum desired number, with replacement of all eight to be accomplished only if outage duration allowed. During the outage, a total of five were in fact installed. Coils were replaced in HVH-18, 19, 20, 21 and 22. Replacement of the coils in HVH-26, 27 and 28 is being planned for the 1987 outage. This issue has been evaluated and prioritized (See Section 3.3.62)

(4) IGSCC Contingency Plan

This contingency plan required personnel and equipment on site to support potential pipe replacement or weld overlay activities identified as a result of the in-service inspection (ISI) program. As a result of the ISI inspections, six welds were in fact weld overlayed. Five of these welds were on the jet pump instrumentation nozzles and one was on the isolation condenser.

(5) Electrical System Oscillograph

This project included the installation and start-up of a digital fault recorder system consisting of two data acquisition units and two matrix printers. The unit continuously monitors various systems and will collect data during a fault or system perturbation from 32 voltage and current inputs and 64 event channels. These include the main generator and transformer, diesel and gas turbine generators, reactor protection system, vital and instrument AC, normal and reserve station service transformers, and 4160 and 480 volt buses.

(6) Voltage Regulators for the Instrument Vital and Reactor Protection Buses

This project included the installation and testing of two 45 kVa single phase regulating transformers and two protection packages consisting of shunt trip circuit breakers and ground fault relays that replaced the existing 50 kVa, IRP-1 and IV-1 dry-type transformers.

(7) Computer Replacement

Activities under this project were limited to the testing and installation of a 600 amp DC breaker that will be the supply breaker for the computer uninterruptible power supply. See Section 3.3.55 for the evaluation and prioritization of the replacement of the plant process computer.

(8) Main Generator Neutral Ground Transformer Replacement

This project included the installation and testing of a 167 kVa dry-type transformer to replace the original PCB filled unit and the installation of a more sensitive stator ground detection scheme.

(9) Gas Turbine Vibration Monitoring System

This project encompassed the installation of a new indicating unit in the gas turbine control house and the installation of new sensors and monitoring units at the gas turbine.

(10) Station Battery Replacement

Station Battery A was replaced with a new IEEE qualified battery. Battery B was replaced during the 1984 outage.

(11) Gas Turbine Battery Replacement

The existing gas turbine battery was replaced with a new 125 VDC power supply.

(12) Replacement of the Switchyard Supervisory and Events Recorder System

During the outage, the remaining Unit No. 1 switchyard breaker and transformer motor operated disconnect controls were transferred to a new unit. The old console was disconnected and removed.

(13) Control Rod Drive Mechanism Change Out

Fifteen control rod drives (CRD) were rebuilt and replaced.

(14) ATWS Power Supply

Input circuitry for the 9N59 ATWS control system was modified to prevent spurious shutdown of the system DC/AC inverters. This modification was made because during a full load reject, the transient overvoltage that would occur on both station batteries would trigger a protective shutdown of the system DC/AC inverters.

(15) Diesel Air Start System Modification Package

The solenoid operating main air start valves on the emergency diesel generator were replaced with improved units. The change was made to enhance the reliability of the emergency diesel generator unit by minimizing the effect of corrosion products in the air start program.

(16) MSRVDL Vacuum Breaker Upgrade

Each of the twelve main steam relief valve drain line (MSRVDL) vacuum breaker valves were modified by replacing several parts of the hinge assembly with higher strength material. Also the disk link was modified such that the point of impact when the disk swings fully open against the valve body is closer to the centroid of the disk assembly.

This change was made to increase safety margins and reliability of the vacuum breakers without changing the time or differential pressure for the valve to open.

(17) Cavity Seal Evaluation/Modifications

Isolation valves were added to the drain lines exiting the drywell. Seismic supports were added to the drain lines exiting the drywell, spent fuel pool gate drain line, and dryer separator drain line. Leak detection instrumentation was added to the inner and outer refueling bellows leak detection lines and a new pool level transmitter was installed with alarms in the control room.

These changes were implemented to satisfy a commitment made to the NRC in response to IE Bulletin 84-03. NNECO committed to make the modifications necessary to prevent the inadvertent draining of the refueling cavity.

(18) Isolation Valve (Line #CUW-143) for Hydrogen Water Chemistry Mini-Test

This project involved adding a back-up isolation valve on the clean-up system return line to the main condenser. This change was made to allow installation of hydrogen water chemistry mini-test piping without a shutdown.

Listed below are projects at Millstone Unit No. 1 that were not assessed in ISAP but had been previously scheduled based on their importance and resources to complete these projects have already been allocated by NNECO.

These projects will not be rescheduled through the ISAP prioritization process but will be factored into the Millstone Unit No. 1 integrated schedule, in recognition of their resource needs.

(1) Main Turbine LP "B" Rotor

The main turbine low pressure "B" rotor is scheduled to be replaced during the 1987 outage. The present rotor contains cracks which are anticipated to continue to grow at a rate that would jeopardize the integrity of the rotor making safe operation of the turbine beyond the 1987 refueling outage uncertain.

(2) Jet Pump Instrumentation Nozzle

The two jet pump instrumentation nozzles (A & B assembly) are scheduled to be replaced during the 1987 outage. During the 1987 outage, five welds on the nozzles (two on A assembly and three on B assembly) had to be weld overlayed due to indications of IGSCC cracks. Because of the stresses already in the nozzles, no additional overlays can be performed. Due to the possibility of finding additional problems in 1987, it was decided to replace the old nozzles with new nozzles.

(3) Reactor Vessel Nozzle Plug

NNECO will procure four main steam line nozzle plugs to be used during the 1987 outage. The existing plugs will be replaced with seismically qualified plugs which do not rely solely on a pneumatically energized retaining force after installation.

(4) Main Generator Surge Protection Capacitors

This project involves replacement of the main generator surge protective capacitors to comply with an internal program to eliminate highly concentrated PCB fluids from the NU system.

(5) Gas Turbine Neutral Grounding Transformer

This project involves replacement of the askarel-filled gas turbine neutral grounding transformer with a non-PCB type transformer. This project will eliminate highly concentrated PCB fluids from the NU system.

(6) Fuel Channels

NNECO will procure and install 200 fuel channels and fasteners for Cycle 12.

(7) MOV Common Mode Failures

In response to IE Bulletin 85-03, all appropriate switch settings on specific motor-operated valves will be evaluated in 1987. In addition, a program will be developed to ensure setting are set and maintained correctly to accommodate the maximum differential

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pressures these valves are subjected to during both normal and abnormal events within the design basis. This project is covered under ISAP Topic No. 2.15 and is addressed in Section 3.3.67 of this report.

(8) Control Rod Blades

NNECO will procure and install 22 replacement control blades for Cycle 12.

(9) IGSCC and Recirculation/RWCU Decontamination

During the 1987 outage, over 150 welds will be inspected for IGSCC. In order to keep radiation exposure as low as possible, the recirculation system and clean-up piping systems may be decontaminated. Contract services will be on standby to either weld overlay or replace sections of pipe if IGSCC cracks are detected.

In Section 3.3 of this report the scope of each topic, the PSA summary, a summary of the topic attributes, and staff PSA review, if applicable, the basis for topic status and the staff conclusions are presented. The proposed topic prioritization list is presented in Chapter 4.

3.3 Evaluation of Topics

3.3.1 Topic 1.01, Gas Turbine Generator Start Logic Modifications

As part of the Millstone Unit No. 1 SEP review (Topic VIII-2), the diesel generator and gas turbine generator (GTG) were reviewed against the criteria of General Design Criterion (GDC) 17, as implemented by Standard Review Plan (SRP) Section 8.3.1 and Branch Technical Position (BTP) ICSB 17, with regard to trips under accident conditions and maintenance programs. As documented in the Integrated Plant Safety Assessment Report (NUREG-0824, IPSAR) Supplement, all of the issues raised in SEP Topic VIII-2 have been resolved, with the exception of bypass under accident conditions of the light-off speed and generator excitation trips, the high lube oil temperature trip and five GTG output breaker protective trips.

In a letter dated August 13, 1985, the licensee proposed to evaluate the safety implications of the outstanding GTG trips, and the need to implement necessary GTG start logic modifications, in the integrated assessment and to prioritize any necessary modifications. By letter dated March 3, 1986, the staff concurred on the licensee's proposed scope of action for this topic.

In a letter dated August 26, 1985, NNECO submitted the PSA summary for this topic. The Millstone Unit No. 1 PSA model identified the fact that 30% of the predicted core melt frequency was due to loss of normal power events, with over half of the resulting sequences dominated by failure of gas turbine bus 14E. Also, failure of the GTG constitutes over 11% of the total core melt frequency. GTG failure is due to either start or run faults which are equally divided in the PSA in terms of their contribution importance. Because the GTG is a major contributor to core melt frequency, the licensee performed a risk evaluation focusing on three areas:

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(1) the light-off speed and generator excitation trips; (2) the high lube oil temperature trip; and (3) five GTG output breaker protective trips.

The results of NNECO's risk analysis showed that improvements in the two areas evaluated (the high temperature lube oil trip is now bypassed under accident conditions) would lead to a reduction in annual core melt frequency of about 4E-6. The staff review of the licensee's risk analysis concluded that the licensee's analysis was generally sound; however, the staff estimated a reduction in annual core melt frequency of about 1.4E-5, significantly higher than the licensee's estimate.

Applying their Analytical Ranking Methodology (ARM), NNECO estimated the public safety attribute score to be 1.0 and the economic performance attribute to be 1.2, on a scale of -10 to +10. NNECO stated that the proposed GTG modifications would result in a small reduction in public risk. The staff rates the importance of the light off speed and generator excitation trips as medium because of the concern about the effect of reliability of the GTG on the estimated station blackout frequency. The staff rates the importance of the five GTG output breaker protective trips as low because of no or small benefit in bypassing these trips. However, the general issue of GTG reliability is important to the overall annual core melt frequency at Millstone Unit No. 1. The GTG, including the maintenance program is discussed in Topic 1.24 and Station Blackout in Section 3.4.1.

3.3.2 Topic 1.02, Tornado Missile Protection

As part of the Millstone Unit No. 1 SEP review (Topic III-4.A), the plant was reviewed against the criteria of GDC 2, as implemented by SRP Sections 3.3.1 and 3.3.2 and Regulatory Guides 1.76 and 1.117, with regard to its ability to withstand the effects of tornado generated missiles. The IPSAR identified those structures and components vulnerable to tornado missiles and it was the staff's position that the licensee was to provide sufficient protection to ensure that the plant could be brought to the hot shutdown condition.

In a letter dated December 2, 1983, the licensee addressed the staff's position. To resolve this open issue, the licensee proposed to rely on the isolation condenser as the primary means for reaching hot shutdown. Also, the licensee committed to provide a connection to the underground city water system and a missile protected pump in the reactor building to supply additional cooling water to the isolation condenser. In a safety evaluation dated November 25, 1985 and as documented in the IPSAR Supplement, the staff concluded that the licensee's proposal will provide adequate protection against tornado missiles. However, because of the importance of the Condensate Storage Tank (CST) and fire-water tanks as cooling water sources, the staff recommended that the capability of the tanks' anchor bolts to provide substantial resistance to wind-load induced failure be confirmed. In a letter dated February 4, 1986, NNECO provided the additional information requested by the staff.

In a letter dated October 16, 1985, the licensee proposed to prioritize the recommended modifications in ISAP. By letter dated March 3, 1986, the staff concurred on the licensee's proposed scope of action for this topic.

In a letter dated August 7, 1985, NNECO submitted the PSA summary for this topic. NNECO evaluated the estimated reduction in core melt frequency that could achieved by implementing the design change to provide for a portable engine driven pump and a protected water supply to provide makeup water. NNECO found that if the design change is implemented, the core melt frequency decreases by about 4.1 E-5 per year, a drop of 5%. However, the licensee notes that 80% of the benefit in core melt frequency does not come from tornado missile initiators but rather from internal events. NNECO estimated the public safety attribute for this topic to be 3.75 on a scale of -10 to +10.

The staff review of the PSA summary found the licensee's core melt frequency attributed to tornado-initiated events to be conservative because the licensee assumed that if a tornado strikes it will do the postulated damage. Given this conservatism, the staff estimates the public safety attribute score to be less than 1 on a scale of -10 to +10.

The staff also noted that this topic and the Topic 1.16 Issue #1 are very closely related (refer to Section 3.2.16). Both issues deal with improving the ability of Millstone Unit No. 1 to withstand a station blackout. The staff found that the modification proposed in Topic 1.16 (Unit 1/Unit 2 Backfeed) would reduce the station blackout frequency by about 4.4E-5 per year. If both the modifications in Topic 1.02 and 1.16 are made, the total core melt frequency reduction is about 6E-5 per year.

NNECO estimated that this topic would have no impact on personnel safety, a small impact on economic performance and a negative impact on personnel productivity due to additional testing, maintenance and surveillance.

During the SEP review of Millstone Unit No. 1, the staff reviewed the capability of the CST and fire-water tanks to withstand a seismic event and found them to be acceptable. The staff has also made a qualitative review of the licensee's February 4, 1986, letter on the adequacy of the CST and fire-water tanks anchorage to withstand tornado wind forces and the staff has inspected the anchorage system during a plant visit. Based on the staff's seismic evaluation, the licensee's analysis and conclusions and the staff's inspection, the staff concludes that it would not be cost beneficial to perform a thorough evaluation of the tank anchorage systems for tornado wind loading. This conclusion is also based on the planned modification to add a protected pump and source of water that would be available if all other sources of cooling water were not available.

Therefore, the staff concludes that NNECO's commitment to install a protected pump and additional source of cooling water adequately resolves the issue of tornado missile protection. The staff ranks this as a medium implementation priority.

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3.3.3 Topic 1.03, Containment Isolation - Appendix A Modifications

As part of the Millstone Unit No. 1 SEP review (Topic VI-4), the isolation provisions for lines penetrating the primary containment were reviewed against the criteria of GDC 54 through 57, as implemented by SRP Section 6.2.4 and Regulatory Guides 1.11 and 1.141. As documented in the IPSAR Supplement, all of the issues raised in SEP Topic VI-4 have been resolved, with the exception of the adequacy of the isolation provisions for penetration X-204, the cooling water return lines that branch off between takeoffs to the containment spray pumps.

In a letter dated October 16, 1985, the licensee proposed to evaluate the potential modifications to penetration X-204 in relation to other NRC requirements (Appendix J Modifications: ISAP Topic 1.14) in the integrated assessment. In a letter dated March 3, 1986, the staff concurred on the licensee's proposal to integrate related Topics 1.03 and 1.14.

However, in a letter dated July 31, 1986, NNECO evaluated this topic separately and proposed to relocate the cooling water return line tie-in to the LPCI suction line from upstream to downstream of pump suction valves 1-LP-2A and 2B. Under the existing arrangement, if the cooling line breaks, it can be isolated only by closing manual valve 1-LP-1A or 1B. In the event of an accident with significant fuel damage compounded by failure of this line, the area would become inaccessible due to high radiation and thus, the break would be unisolable. The torus water would slowly drain outside containment and would constitute a release pathway. Relocation of the tie-in would provide capability to open the valves from a safe location.

NNECO points out that relocating the tie-in would not reduce the CMF but would reduce the release outside containment. However, since the piping is only 3/4 inch, the expected release, given significant fuel damage followed by a break in this line, would be small compared to other sources. Also, the frequency of accidents resulting in limited fuel damage is 3E-3/yr. The combination of such an accident with coincident failure of the cooling water return line is very low, about 1E-8/yr using WASH-1400 pipe failure data.

The staff has reviewed the isolation provisions for penetrations X-204 and concludes that the overall safety significance is low compared to other release pathways following an accident with fuel failure. The staff finds that the implementation priority of this topic should be low.

3.3.4 Topic 1.04, RWCU System Pressure Interlock

As part of the Millstone Unit No. 1 SEP review (Topic V-11.A), the redundancy and diversity of pressure interlocks for motor-operated valves which isolate the high pressure systems from low pressure systems were evaluated against the criteria of 10 CFR 50.55a, as implemented by SRP Section 7.6 and BTP ICSB 3. As documented in the IPSAR, it was recommended that the licensee either demonstrate the adequacy of the Reactor Water Cleanup System (RWCU) relief valve or install an independent pressure interlock for actuation of the RWCU system isolation on high pressure. The licensee chose to install an independent pressure interlock for the inboard suction isolation valve.

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In a letter dated August 13, 1985, the licensee proposed to evaluate the adequacy of the RWCU relief valve and the need for an independent pressure interlock with the priority of the evaluation and modification to be determined in the integrated assessment. This type of evaluation was an alternative to system modifications available to Millstone Unit No. 1 and the other plants that participated in SEP. The results of the system evaluation in concert with the PSA findings will be used to determine what, if any, plant modifications are appropriate. In a letter dated March 3, 1986, the staff concurred on the licensee's proposed scope of the evaluation.

In a letter dated August 23, 1985, NNECO submitted the PSA summary for this topic. The PSA summary investigated the installation of a second, independent pressure interlock to ensure system isolation in the event that the pressure regulating valve fails wide open. The frequencies calculated for the initiators for this event were used to requantify the frequency of an interfacing systems LOCA and small LOCA core melt. In the case of the interfacing systems LOCA, the frequency prior to the "fix" was considered so small (3E-9 per year) that further analysis was not required. For the small LOCA case, the "fix" resulted in a core melt reduction of 3E-8 per year. This difference, when applied to the public safety attribute, yielded a score of 0.01 on a scale of -10 to +10.

The staff review of the licensee's PSA summary found the licensee's assumption of not taking credit for the isolation signal to the valves from the RPS on low reactor water level to be conservative since core damage will not occur prior to reaching the low level setpoint. The staff recalculated the PSA analysis taking credit for the isolation signal and found that valve failure and not failure of the isolation signal or high temperature signal dominate the failure probability. The staff concluded that the addition of a second, independent pressure interlock would not alter the probability of a failure to isolate the RWCU line in the case of a failure of the pressure regulating valve.

In addition, NNECO performed a calculation that demonstrated that if the pressure regulating valve failed wide open, the large capacity relief valve would have more than enough capacity to discharge the anticipated line flow at the expected temperature and pressure. Therefore, given the relief capacity of the RWCU and the PSA results, we conclude that the addition of an independent pressure interlock is not warranted and that this topic is resolved.

3.3.5 Topic 1.05, Ventilation Systems

As part of the Millstone Unit No. 1 SEP review (Topic IX-5), the ventilation systems were reviewed against the criteria of GDC 4, 60 and 61, as implemented by SRP Sections 9.4.1 through 9.4.5, with regard to the capability to provide a safe environment for plant personnel and safety features. As documented in the IPSAR Supplement, all of the issues raised in the SEP review were resolved except for providing emergency power to the feedwater coolant injection system (FWCI) space coolers and to the intake structure ventilation system. The licensee committed to make the necessary modifications to the ventilation systems to resolve this issue.

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In a letter dated August 13, 1985, the licensee proposed to evaluate the conservatisms in the ventilation system's design limits and use risk insights and best estimate success criteria from the PSA to determine the need to implement the modifications, and, if necessary, to determine a priority for implementation. In a letter dated March 3, 1986, the staff concurred on the scope of the licensee's proposed evaluation.

In a letter dated September 12, 1985, NNECO submitted the PSA summary for this topic. The PSA summary investigated:

(1) The modification of the electrical supplies for the feedwater/FWCI area coolers so that all six coolers will be automatically sequenced onto a GTG powered bus following a LNP. Currently, only two of six area coolers will automatically restart.

(2) The modification of the power supply for the intake structure exhaust fans to allow automatic sequencing of one fan onto a gas turbine generator bus and the other fan onto a diesel generator bus.

NNECO's analysis for Item (1) indicated a 35% increase in core melt frequency due to inadequate ventilation of the FWCI area. The public safety attribute score for this modification was 10 on a scale of -10 to +10. NNECO's analysis for Item (2) showed, given a worst case scenario with no ventilation and two service water pumps running, that the potential heat buildup in the intake structure would not affect pump performance. In other words, it appears that failure of the intake structure ventilation following an LNP event would not lead to failure of the service water or emergency service water systems. The public safety attribute score for this modification was 0 on a scale of -10 to +10. NNECO estimated that the proposed modifications would not affect personnel safety, economic performance or personnel productivity.

The staff review of the PSA analyses concluded that the analyses were acceptable. The staff review of the attribute scores for this topic are in agreement with the licensee, that the priority of this topic is high.

3.3.6 Topic 1.06, Seismic Qualification of Safety Related Piping

IE Bulletin 79-02 requires licensees to verify the adequacy of pipe support base plates and expansion anchor bolts utilized in supporting safety-related piping. IE Bulletin 79-14 requires licensees to verify that seismic analyses performed on safety-related piping systems apply to the actual configuration of the safety-related piping systems. The review was conducted to the criteria in the bulletins, Regulatory Guide 1.29 and the Millstone Unit No. 1 FSAR.

IE Inspection Report 50/245/85-04, dated April 18, 1985, reviewed the licensee's completeness of response to IE Bulletins 79-02 and 79-14. The scope of the inspection included a review of engineering design and quality assurance documentation to verify that the licensee had met bulletin requirements. Also, a walkdown inspection of the plant was conducted to verify repairs relating to the bulletins. No violations were reported.

In a letter dated October 11, 1985, NNECO stated that approximately 1100 modifications were identified. NNECO planned to implement about 100 pipe support modifications during the November 1985 refueling outage. To date approximately 300 modifications remain. The scope of work in the 1985 outage reflected the results of NNECO's August 23, 1985, pipe support risk analyses. As a result of those analyses, the high priority modifications were incorporated into the outage work scope. With respect to the remaining modifications, NNECO's position is that since analysis has shown that the remaining modifications will not provide a significant improvement in safety, a priority for implementation should be determined in ISAP. In a letter dated March 3, 1986, the staff concurred on the scope of this topic in the integrated assessment.

In a letter dated August 23, 1985, NNECO provided the PSA summary for this topic. As a result of IE Bulletin 79-14, all modifications necessary to qualify piping to the Operating Basis Earthquake (ground acceration 0.07g) have been completed. Most modifications necessary to qualify piping to Safe Shutdown Earthquake (ground acceleration 0.17g) have been completed. The PSA summary investigated the modification of the remaining pipe supports to qualify the piping to Safe Shutdown Earthquake. The public safety attribute was calculated using Method B because of the difficulty of quantifying external event probabilities.

NNECO based their evaluation on data collected by the Seismic Qualification Utility Group, the Senior Seismic Review Advisory Panel and the NRC. These groups concluded that mechanical and electrical equipment of types commonly used in nuclear power plants are unlikely to fail at earthquake levels typical for the Safe Shutdown Earthquakes on the east coast. Also, past PRAs have shown that piping typically has higher fragilities than other systems, so that no significant improvement on public risk would be expected if the remaining supports are modified. NNECO assigned a public safety attribute score of 0.1 on a scale of -10 to +10 to this topic. NNECO estimated that the plant modifications would not impact economic performance, but would have a negative impact on personnel safety and personnel because many of the supports are located in radiation areas and would require maintenance and may interfere with testing.

The staff review of the PSA summary for this topic was in general agreement with the licensee's conclusions except that the staff recommends that a review of the remaining piping modifications be performed to determine if any would be susceptible to potential displacement failure modes.

Also, the staff notes that the present stress analysis at Millstone Unit No. 1 is based upon the installation of the remaining piping modification. Therefore, even though this topic was estimated by NNECO to have an ARM score of 0.0, the staff position is that since these modifications are part of the plant design basis they should be completed, using a priority commensurate with their low safety significance, or NNECO should recalculate the stress analysis to reflect the missing piping supports using state of the art methods and criteria.

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3.3.7 Topic 1.07, Control Room Design Review

As part of the generic requirements of the TMI Action plan, identified in NUREG-0737 Supplement 1 and as implemented by Generic Letter 82-33, all licensees and applicants for operating licenses are to conduct a detailed control room design review. This review is intended to improve the ability of operators to prevent accidents or cope with accidents by identifying any modifications of control room configurations that would contribute to a significant risk reduction or improvement in safety.

By letters dated April 15, August 11, November 28 and December 20, 1983 and April 9, 1984, NNECO provided the schedule and plans for completing the requirements detailed in Generic Letter 82-33. The schedule for the control room design review called for a program plan and a summary report, including a proposed schedule for implementation, to be submitted to the NRC by March 2, 1987. The staff concurred on this schedule and on June 12, 1984 issued an order confirming NNECO's commitment.

In a letter dated October 16, 1985, NNECO proposed that the schedule for the control room design review be evaluated and prioritized in ISAP. In a letter dated March 3, 1986, the staff concurred in the licensee's proposed scope for this topic in the integrated assessment.

In a letter dated August 23, 1986, NNECO submitted the PSA summary for this topic. The PSA summary evaluated, by means of Method B, the benefits of a systematic review of control room design for the identification of possible control room design changes. The review will include the following areas:

(1) Identification of control room operator tasks, and information and control requirements during emergency operations.

(2) A comparison of the display and control requirements with a control room inventory to identify missing displays and controls.

(3) A control room survey to identify deviations from accepted human factors principles.

Three potential sources of benefits were considered and these are:

(1) Avoiding human error caused transients.
(2) Avoiding human error caused system unavailability.
(3) Avoiding cognitive errors due to instrument deficiencies.

NNECO's evaluation of the potential benefits of a control room design review concluded that given the improvements in the control room design already achieved in the last 15 years, any further improvements to control room layout are not expected to provide any significant improvement in human reliability of the operator during an emergency.

NNECO, based on engineering judgment, gave this topic a public safety attribute score of 0.1 on a scale of -10 to +10. NNECO estimated that any modifications resulting from this topic would have no effect on personnel safety or personnel productivity; however, the modifications could enhance the operator's reliability in day-to-day operation of the plant and, therefore, would provide a small benefit in economic performance.

The staff noted during its review of the PSA that NNECO did not identify any CRDR faults as important initiators of accidents. NNECO met its March 2, 1987, commitment date for submitting the program plan and schedule for the control room design review, and is currently under staff review.

3.3.8 Topic 1.08, Safety Parameter Display System

As part of the generic requirements of the TMI Action plan, identified in NUREG-0737 Supplement 1 and as implemented by Generic Letter 82-33, all licensees are to provide a Safety Parameter Display System. This system is to display to the operators a minimum set of parameters defining the safety status of the plant and be capable of displaying a full range of important plant parameters and data trends on demand, and be capable of indicating when process limits are being approached or exceeded.

By letters dated April 15, August 11, November 28 and December 20, 1983 and April 9, 1984, NNECO provided the schedule and plans for completing the requirements detailed in Generic Letter 82-33. The schedule for meeting the Safety Parameter Display System requirements calls for the submittal of a safety analysis and plan by April 9, 1987. The staff concurred on this schedule and on June 12, 1984 issued an order confirming NNECO's commitment.

In a letter dated October 16, 1985, NNECO proposed that the schedule for the Safety Parameter Display System be evaluated and prioritized in ISAP. In a letter dated March 3, 1986, the staff concurred in the scope for this topic for the integrated assessment.

NNECO's public safety attribute assessment found that the SPDS does not provide any new information to the operator since all of the information is currently available on the control board. However, NNECO stated that the SPDS could potentially be beneficial in events such as an ATWS or large break LOCA and, therefore, NNECO scored this topic as a 1 on a scale of -10 to +10. NNECO estimated that the SPDS will have no impact on personnel safety, economic performance or personnel productivity.

It is the staff's position that, given the fact that the plant process computer and associated equipment, such as an uninterruptible power supply, is already being upgraded or replaced, priority score for this topic should be higher. The staff feels that NNECO's priority score did not reflect intangible benefits such as unique displays of plant operating information, trending and a single location for reference to find the information. These benefits could result in an unquantifiable increase

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in operator reliability. Therefore, the staff concludes that, while not a high priority item, the installation schedule of the SPDS that is due to be submitted by April 9, 1987, should reflect a higher priority than that (low) assigned by NNECO.

3.3.9 Topic 1.09, Regulatory Guide 1.97 Instrumentation

As part of the generic requirements of the TMI Action Plan, identified in NUREG-0737 Supplement 1 and as implemented by Regulatory Guide 1.97, Rev. 2, licensees and applicants for operating licenses are required to provide instrumentation to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences and for accident conditions to assure safety. Regulatory Guide 1.97, Rev. 2, identifies parameters to be monitored, ranks the parameters according to the importance of their function, and provides recommended ranges for the parameters.

In a letter dated March 11, 1985, the staff issued an interim report to NNECO regarding the results of their review of the NNECO submittals on Regulatory Guide 1.97 for Millstone Unit No. 1. In that report, the staff indicated that the information submitted by NNECO was acceptable with the exception of the following items which require additional justification.

(1) Environmental qualification - there are five Category 2 variables for which environmental qualification should be addressed in accordance with 10 CFR 50.49.

(2) Power source - there are four Category 1 variables for which the licensee should provide independent Class 1E power sources for each of the redundant channels.

(3) Coolant level in reactor - the licensee should justify the non-redundant instrumentation from +60 in. to the centerline of the main steamline.

(4) Drywell sump level - the licensee should provide additional justification for deviating from the recommendations for this variable.

(5) Drywell drains sump level - the licensee should provide additional justification for deviating from the recommendations for this variable.

(6) Containment drywell hydrogen concentration - the licensee should show that the post-accident sampling system is a viable alternative means of obtaining this information.

(7) Containment drywell oxygen concentration - the licensee should show that the post-accident sampling system is a viable alternative means of obtaining this information.

(8) Radiation exposure rate - the licensee should identify the ranges and locations of these instruments.

(9) Main feedwater flow - environmental qualification should be addressed in accordance with 10 CFR 50.49.

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(10) Suppression chamber spray flow - the licensee should provide additional justification in support of their deviation.

(11) Drywell spray flow - the licensee should provide additional justification in support of their deviation.

(12) Standby liquid control system flow - the licensee should provide additional justification for the alternative instrumentation.

(13) Residual heat removal system flow - the licensee should provide additional justification for the alternative instrumentation.

(14) Cooling water flow to ESF system components - the licensee should show that the instrumentation for pump discharge pressure meets the Category 2 requirements.

(15) High radioactivity liquid tank level - the licensee should justify the use of high and low level alarms in lieu of continuous level indication.

(16) Reactor building or secondary containment area radiation - the licensee should provide additional justification for not implementing this variable.

By letter dated October 25, 1985, NNECO identified the scope of ISAP Topic 1.09 as addressing the conformance of Millstone Unit No. 1 with the recommendations of Regulatory Guide 1.97, Rev. 2. Also, in that letter, NNECO addressed the 16 items, listed above, identified in the staff's interim report. The licensee has provided additional information as requested, identified some items to be specifically evaluated in the ISAP integrated assessment, or stated that evaluations of items are still ongoing.

In NNECO's October 25, 1985, letter NNECO identified nine modifications within the scope of the ISAP topic that would be necessary to bring Millstone Unit No. 1 into conformance with the recommendations of Regulatory Guide 1.97. Also, NNECO stated that the evaluation of main feedwater flow and cooling water flow to ESF system components are still being evaluated within the scope of ISAP. Also, the issues that relate to containment hydrogen and oxygen concentrations are not discussed here, but are presented in Section 3.3.11 of this report.

NNECO addressed their nine proposed modifications in relation to the attribute scores. Their evaluation has shown that most of the modifications provide little or no safety benefit, while some might provide a significant benefit. NNECO stated that further effort on this topic is necessary to definitively determine which modifications provide significant benefits and thus merit implementation. NNECO's public safety attribute evaluation for each of the nine proposed modifications is presented below.

(1) RPV Pressure: In the current design, there are redundant, safety grade instruments (with separate power sources) for the range of 0 to 1,200 psig. Although there are two wide range (0 - 2,500 psig) pressure instruments available, both are powered by instrument AC. This proposal involves redundant instruments (with separate power sources) for indications of pressure above 1,200 psig.

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In all transients, except an ATWS with MSIV closure, the RPV pressure remains below 1,200 psig because the turbine bypass valves and safety relief valves control pressure well below 1,200 psig. In an ATWS with MSIV closure, the RPV pressure momentarily increases above 1,200 psig. As the core power decreases, the pressure falls below 1,200 psig, possible loss of indication (due to instrument failure) would not inhibit any transient mitigation efforts. No operator decisions require a pressure reading above 1,200 psig, and none of the mitigating systems are automatically initiated off a pressure signal above 1,200 psig.

Therefore, providing redundant power sources for the wide range (0-2500 psig) pressure instrumentation would result in no reduction in core melt frequency or public risk. The staff ranks the implementation priority of this issue as low.

(2) RPV Water Level: This proposed project involves redundant instruments to measure RPV water level in the range of +60" to centerline of steam line (at +122"). In the current design, there are redundant instruments (with separate power sources) available for water level indication between +60" and the bottom of the coreplate. There is a concern that due to a single failure all indications of water level above +60" could be lost. It should be noted that normal water level (while at power) is +30". Therefore, loss of indication will affect only those scenarios in which the water level is considerably above the normal value.

Following a transient, the emergency operating procedures (EOPs) direct the operator to recover and maintain water level to the normal value. Also, automatic initiation of all mitigating systems occurs when the water level is below 60". Redundant instruments which are available to measure level below 60" provide safeguards against a single failure causing loss of level indication for operator action or for automatic initiation of mitigating systems.

Only in alternate shutdown cooling (SDC) mode of long-term heat removal operation, will the operator increase the water level above +30" to establish a flow path through the open safety/relief valve back to the torus. However, in alternate SDC, the operator does not need to know water level. Success of alternate SDC is inferred from the cool-down rate, number of safety relief valves (SRVs) open and RPV pressure.

Therefore, providing redundant level instrumentation for water level above +60" for this scenario would provide no reduction in core melt frequency or public risk. However, there is a concern that a single failure can eliminate all indications of water level above 60 inches. The staff believes that positive water level indication is important at all times. The staff ranks the implementation priority of this issue as medium.

(3) Neutron Flux: This proposed project involves environmentally qualified instruments with redundant channels and separate power sources for neutron flux measurement. Neutron flux is an important

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parameter to monitor during startup, shutdown and power operation. In the current design, the instruments to measure neutron flux are not environmentally qualified. The staff is aware that there are no instruments currently available that would meet environmental qualification standards. There is a concern that the operator may lose ability to determine core power following a transient. This could happen due to the harsh environment caused by a LOCA in the drywell or reactor building, or due to loss of power for the instrumentation.

There are several features at Millstone Unit No. 1 that can compensate for the potential loss of instrumentation. In the Millstone Unit No. 1 design, each of the control rods has position indications and full-in and full-out lights. Following a reactor trip, the operator can infer subcriticality of the reactor by reviewing the rod position. If all control rods are inserted, subcriticality is ensured and none of the subsequent operator actions require knowledge of core power level.

If at least two adjacent rods stick out, an instrument reading is needed to ensure core subcriticality. With failure of neutron flux measurement, the operator will not be able to determine the core power and therefore will classify the event as an ATWS. None of the subsequent operator actions described in ATWS mitigating procedures, however, require knowledge of core power level. For this low probability scenario, loss of neutron flux monitoring will be only in inconvenience. The loss will not prevent the operator from bringing the plant down to cold shutdown. This proposed modification would provide an insignificant reduction in public risk. The staff ranks the implementation priority of environmental qualification as low.

As stated previously, neutron flux measurement is important during startup, shutdown and plant operations. For a transient without a rapid reactor trip, neutron flux measurement may be important because the signal is an input to control systems and gives the operator direct, visual confirmation of the nuclear power level. Therefore, the staff considers it prudent to modify the power supplies to the neutron flux instruments (from sensors to isolation devices or protection system inputs) to assure that no single failure will prevent neutron flux measurements from being able to meet their safety functions. The staff rates this recommended modification as medium.

(4) Drywell Temperature: This project involves environmentally qualified temperature indicators. In the current design, these temperature indicators may not be qualified for harsh environment. There is a concern that following a LOCA or steam line break in the drywell which creates a harsh environment, the drywell temperature indication may fail.

The existing emergency operating procedure cautions the operator that RPV water level indications may fail when the drywell temperature reaches the RPV saturation temperature. This failure of level indication is due to reference leg flashing. The failure mode is such that the operator will see an increase in RPV water level, even if the actual level is not varying. With potential failure of the drywell temperature indicators due to harsh environment, the operator will not know when the level indications have failed. If the operator controls the RPV water level based on the erroneous indicated level, the core may uncover leading to fuel damage.

The EOP also requires the operator to depressurize the RPV if the drywell temperature exceeds 281°F. Due to failure of the drywell temperature, the operator may not carry out this action in time (i.e., before the SRVs fail due to high temperature). Thus, the capability of depressurizing RPV using the SRVs may be lost. Such a depressurization may be needed for small breaks to allow injection with low pressure pumps.

Considering the effect of loss of drywell temperature indication on RPV level instrumentation and equipment operability, and therefore its importance to mitigate a LOCA, this project will have a small public safety benefit and the staff ranks it as medium.

(5) Drywell Spray Flow: The proposed project involves providing redundant and environmentally qualified instruments to measure drywell spray flow rate. In the current Millstone Unit No. 1 design, drywell spray flow rate cannot be measured. In accordance with the existing EOPs, very restrictive conditions exist for which the drywell sprays can be utilized post-accident. In addition, no current design basis analysis credits the use of drywell sprays. Addition of drywell spray measuring instruments was calculated by NNECO to decrease the core melt frequency by 2.5×10^{-7}/year, which results in a slight decrease in public risk.

Addition of drywell spray flow measuring instrument could ease the restrictive conditions to initiate the spray flow, provided adequate capability to control drywell spray flow existed. The benefit of adding drywell spray flow measuring instruments was calculated assuming the flow measurement will allow the operator to initiate drywell spray when needed (i.e., adequate capability to control spray flow did exist and EOP restrictions would not prohibit use of spray). In the current design (without flow measurements), it is assumed that the operator would not be able to initiate spray flow for all scenarios.

The major benefit from the drywell sprays involves their use following a core melt accident to cool core debris, reduce containment atmosphere temperature and scrub fission products from the containment atmosphere. In this mode the drywell sprays may be able to prevent breach of containment or reduce the source term by up to two orders of magnitude. If adequate and appropriate drywell spray flow can be supplied to the drywell following a core melt accident without use of drywell spray instrumentation (e.g. by installing restrictive orfices and smaller spray nozzles), then the staff rates this as Low. If the drywell spray flow rate is necessary to assure appropriate flow, the staff rates this as high. The exact staff rating depends on what other modifications, if any, NNECO proposes for the drywell spray system.

(6) Isolation Condenser Shell Side Water Level: This project proposes replacing the presently installed IC shell side water level instrument, which is not proven to be qualified for harsh environment, with a qualified instrument. The water level instrument provides level indication to the operator. Also, make-up to the shell side is automatically initiated on low level based on this instrumentation. There is a concern that with failure of level instrumentation, make-up to the IC shell side may not automatically start and indication to the operator may be incorrect. An incorrect level indication may mislead the operator with respect to the need for manually initiating the make-up flow. In the worst case scenario, the IC could lose its function due to a loss of shell side inventory. NNECO evaluated this worst case scenario.

The water level instrumentation for IC shell side is located in the reactor building. A break inside the reactor building which can create a harsh environment, and thus potential instrumentation failure, is a low frequency event (less than 1E-5 per year). The IC can mitigate the event if the break can be isolated. For an unisolable break in the reactor building, the IC does not provide any benefit. This is because ultimately all inventory will be lost through the break, resulting in severe core damage. An isolable break in the reactor building can be mitigated by many systems other than the IC. If the isolation condenser level instrumentation is lost, the operator may provide either too little or too much flow to the shell side. If it is too little, level will drop and core cooling will be reduced. The operator will see primary system pressure and temperature increase. If the flow is too large, level will increase and eventually flow harmlessly out the vent line.

The public safety benefit of qualifying IC shell side water level instrumentation was estimated by NNECO by assuming that without such modification, the IC cannot be used to mitigate a break in the reactor building. NNECO concluded that providing a qualified IC shell side water level instrumentation results is an insignificant improvement in core melt frequency 8.0E-9 per year and therefore a negligible reduction in public risk. The staff ranks the implementation priority of this issue low.

(7) Ventilation Damper Position: The public safety benefit of providing environmentally qualified redundant position indications was included in the evaluation of ISAP Topic No. 1.12 Control Room Habitability, (refer to Section 3.3.12 of this report)

(8) Primary Containment Isolation Valve Position Indications: NNECO addressed in its evaluation both the proposed IC system valve position indication and the proposed containment isolation valve position indications. In the current design, the valve position indications are either no environmentally qualified or do not have

> redundant power sources. The proposal is to correct these perceived deficiencies. NNECO's analysis, however, concluded that loss of these valve position indications is not critical in limiting off-site dose.
>
> First, closing the valves is important to reduce release only in the sequences leading to significant fuel damage. The frequency of such sequences is low. Second, the stack monitoring and alarm system provides indication of any appreciable release in the reactor building and turbine building. Loss of valve position indication does not imply that the valve will not function (i.e., close automatically or manually). If the stack monitoring indicates that a release is occurring and the operator is not certain that all containment isolation valves are closed (due to loss of position indication), the operator will assume that the valves are open and will close them from the control room. Therefore, loss of indication does not inhibit the operator from minimizing the offsite dose.
>
> NNECO estimated that this topic would have a small negative impact on personnel safety and no impact on economic performance or personnel productivity. However, the staff based on the potential for ECCS flow diversion and based on ALARA considerations, ranks the implementation priority of this issue as medium.

The staff currently has the information submitted by NNECO on this topic under evaluation. In addition the staff has evaluated the priority of the main feedwater flow and cooling water flow to the ESF system components issues. The Millstone Unit No. 1 PSA highlights the importance of the main feedwater (FWCI) flow in LOCA and transient situations. The staff ranks the implementation priority of this issue as medium. Due to the importance of maintaining cooling water flow to ESF system components, the staff ranks the implementation priority of this issue to medium. While the staff's evaluation of the NNECO submittal is not yet complete, it is the staff's position that the implementation of any modifications be according to the priorities presented above.

3.3.10 Topic 1.10, Emergency Response Facilities Instrumentation

As part of the generic requirements of the TMI Action plan, identified in NUREG-0737 Supplement 1 and as implemented by Generic Letter 82-33 and Regulatory Guide 1.97, Rev. 2, all licensees and applicants for operating licenses are to provide an Emergency Response Facility (ERF) with appropriate instrumentation. Millstone Unit No. 1 has an approved ERF.

By letter dated October 24, 1985, NNECO stated that the final list of variables to be displayed is currently being developed and will be provided at a later date.

NNECO has evaluated the public safety attribute for this topic and found it to score a 1.0 on a scale of -10 to +10. NNECO stated that some type of plant monitoring capability would be needed for the technical support center. If the technical support center had rapid access to the same information as their counterparts in the control room, there is a potential for devising solutions to problems not addressed in the procedures. However, similar information needs do not exist for the emergency operations facility. Personnel in this facility are involved in broader concerns such as dose rate estimates. The final emergency response facilities capabilities are to be considered together with the Regulatory Guide 1.97 instrumentation (refer to Section 3.3.9).

The staff has reviewed the attribute scores for this topic and the proposal method of resolution and finds them to be adequate and rates the implementation priority of this topic as low.

3.3.11 Topic 1.11, Post-Accident Hydrogen Monitor

As part of the generic requirements of the TMI Action Plan, identified in NUREG-0737 Supplement 1 and as implemented by Generic Letter 83-28 all licensees and applicants for an operating license are required to monitor containment hydrogen concentrations.

In response to the requirements of 10 CFR 50.44, NNECO claimed the benefit of the normally inerted atmosphere during reactor operation for its Mark I BWR containment. Inerting reduces the potential for combustion or deflagration by reducing the oxygen content in the containment atmosphere to a level where it is not capable of reacting with hydrogen produced by an accident. In response to the post-accident hydrogen monitor requirements of the TMI Action Plan, NNECO installed a single channel hydrogen monitoring system.

By letter dated July 30, 1984, the staff issued a safety evaluation for the Millstone Unit No. 1 post-accident hydrogen monitoring system and concluded that the monitoring system meets the TMI Action Plan requirements with the exception of redundancy. However, it was noted that Millstone Unit No. 1 has the capability to determine both hydrogen and oxygen concentrations through the use of the Post-Accident Sampling System (PASS). This system provides only grab samples. In its safety evaluation the staff indicated that NNECO should demonstrate that the sampling and analysis frequency of the PASS is sufficient to respond to any rapid changes in hydrogen or oxygen concentration before the single channel analyzer can be considered acceptable.

By letter dated November 25, 1985, NNECO reiterated its position on the acceptability of the hydrogen monitoring system as installed at Millstone Unit No. 1 and stated that further information supporting this conclusion will be submitted in early 1986. In a letter dated March 3, 1986, the staff concurred in the scope for this topic in the integrated assessment.

In a letter dated July 31, 1986, NNECO responded to the staff's concerns and provided additional information. The staff has noted that the primary purpose of continuous hydrogen/oxygen monitors in containments is to detect and assess the potential for a combustible gas mixture during the first few hours after a LOCA. The backup monitoring capability of the PASS (3 hour sample analyzing period) is not available during the first few hours after a LOCA.

The DBA LOCA analysis for Millstone Unit No. 1 assumes that the containment is inerted at the time the LOCA occurs. Previous analysis has shown that under this circumstance, the potential for combustible mixtures is negligible. In addition, should a beyond DBA LOCA occur when the containment is not inerted, Millstone Unit No. 1 plant design does not incorporate the capability to mitigate the resulting combustible gas mixture except by venting, whether or not it is identified by the monitoring system. However, it should be noted that the probability of this event is extremely low and at present the staff is still developing a policy for coping with beyond DBA events in operating reactors.

The staff is currently reviewing the July 31, 1986, submittal to determine if the single channel containment hydrogen monitoring system is an acceptable deviation from the staff guidelines for redundancy for a plant with an inerted containment. This issue applies to other BWRs that similarly rely on the inerted containment as the primary means of combustible gas control. The affected BWR licensees intend to submit a joint response to the staff's concerns.

3.3.12 Topic 1.12, Control Room Habitability

As part of the generic requirements of the TMI Action plan, identified in NUREG-0737 Supplement 1 and as implemented by Generic Letter 82-33, all licensees were to assure that control room operators are adequately protected against the effects of an accidental release of toxic or radioactive gases and that the nuclear power plant can be safely shutdown under design basis accident conditions.

By letter dated October 24, 1985, NNECO proposed to evaluate alternative methods of protecting control room operators, because of the high cost of control room heating, ventillation and air conditioning (HVAC) design modifications, in ISAP. In a letter dated March 3, 1986, the staff concurred on the licensee's proposed evaluation to resolve this topic.

In a letter dated September 6, 1985, NNECO submitted the PSA summary for this topic. The PSA summary investigated the benefits of the following modifications to the (HVAC) system:

(1) Air conditioning to the control room using recirculation and outside air make-up during normal operation.

(2) Automatic isolation of air intake upon detection of high radiation or chlorine gas.

(3) Total recirculation of air by routing air flow through charcoal filters during high radiation or chlorine gas release.

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Using Methods A and B, NNECO evaluated three scenarios to determine the reduction in risk resulting from the proposed plant modifications. These scenarios are:

(1) Habitability following a high radiation release;

(2) Habitability following a large chlorine gas release; and

(3) Potential operator error due to loss of HVAC system during normal operation.

NNECO concluded that the benefits associated with the control room habitability improvements will reduce core melt frequency by 1.17E-6 per year, which translates to a public safety attribute score of 0.5 on a scale of -10 to +10. The staff review of the PSA summary showed that the majority of the benefits would come from scenarios involving high radiation release. The staff feels that the chlorine release probability used by NNECO is overly conservative (refer to Section 3.2.59), in fact, the onsite storage of chlorine in railroad tank cars was discontinued in 1986. Also the potential for operator error was not included because it is part of Topic 1.07 (refer to Section 3.2.7). Thus, although a moot issue the staff concludes that the public safety attribute score should be closer to 0.1 on a scale of -10 to +10.

NNECO estimated that: the economic performance attribute score would be 0.1 on a scale of -10 to +10 due to increased reliability of the HVAC system; the personnel safety attribute score would be -2.6 due to increased exposure and special maintenance and testing; the personnel productivity attribute score would be -2 due to increased workload.

The staff has reviewed the priority attribute scores for this topic and finds them to be reasonable except that the staff believes that the attribute score should be medium. Without the improvement in control room HVAC, plant operators would be required to wear air packs following certain accidents.

The staff notes that these airpacks restrict an operators vision and in the long term may lead to increased operator stress resulting in a decrease in reliability.

It is the staff's position that the priority score for this topic should be higher then proposed by NNECO, but when designing the HVAC system improvements, NNECO should develop a design based on cost effectiveness.

3.3.13 Topic 1.13, BWR Vessel Water Level Instrumentation

As part of the generic requirements of the TMI Action plan, as identified in NUREG-0737 and as implemented by Generic Letter 84-23, licensees were to modify or supplement existing equipment to assure accurate indication of vessel water level.

In a letter dated October 11, 1985, the licensee presented a concern (i.e., reference leg flashing) which could produce inaccuracies in vessel water level monitoring. The licensee proposed to investigate different approaches to resolve the reference leg flashing issue and to investigate the need for further evaluation of the water level instrumentation in the integrated assessment. In a letter dated March 3, 1986, the staff concurred on the licensee's proposed scope for this topic.

In a letter dated September 6, 1985, NNECO provided the PSA summary for this topic. The PSA summary investigated the problem of reference leg flashing in producing cognitive errors involving failure to control water level. The PSA summary stated that if reference leg flashing is a problem at Millstone Unit No. 1 and if a fix can be made to eliminate the problem, a reduction of 1.6 E-5 per year in the core melt frequency is possible. This reduction is translated to a public safety attribute score of 1.5 on a scale of -10 to +10. This modification would have little, if any, impact on the other attribute scores.

The staff's review of the PSA summary of this topic concluded that NNECO's analysis is acceptable. The staff review of the attribute scores for this topic finds NNECO's estimate to be acceptable. The staff also agrees with the licensee's medium priority for this topic.

3.3.14 Topic 1.14, Appendix J Modifications

Appendix J to 10 CFR 50, "Primary Reactor Containment Leakage Testing for Water-Cooled Reactors," was issued in 1973, more than two years after the POL was issued for Millstone Unit No. 1. An NRC concern that plants completed or reaching an advanced stage of design or construction by the time of the issuance of the regulation prompted a request to licensees to determine if they were in full compliance with Appendix J. Specifically, NNECO was requested to identify any design features that do not permit conformance to the requirements and to identify existing technical specifications which are in conflict with Appendix J.

By letter dated October 16, 1985, NNECO proposed to evaluate the current status of Millstone Unit No. 1 compliance with the requirements of Appendix J in ISAP. NNECO intends to identify remaining areas of noncompliance from Topic 1.03, propose acceptable means of addressing all open issues and develop schedules for resolution of such issues. In a letter dated March 3, 1986, the staff concurred on the licensee's proposed scope for this topic and rates the implementation priority for the evaluation as medium.

3.3.15 Topic 1.15, FSAR Update

Section 50.71(e)(3)(ii) of 10 CFR Part 50 requires that those plants initially subject to the NRC's Systematic Evaluation Program (SEP) must file a complete updated Final Safety Analysis Report within 24 months after receipt of notification that the SEP has been completed. By letter dated March 16, 1983, the staff informed NNECO that SEP had been completed for Millstone Unit No. 1 and that, pursuant to 10 CFR 50.71(e)(3)(ii), the licensee was required to file an updated Final Safety Analysis Report (FSAR). In the original NNECO Millstone Unit No. 1 ISAP proposal, dated December 28, 1983, NNECO proposed to establish the schedule for the FSAR update in an integrated assessment of all issues. Later, by letter dated February 4, 1985, the licensee requested an exemption to defer submittal of the updated FSAR on the bases that ongoing reviews (e.g., the Integrated Safety Assessment Program) would directly affect the content of the updated FSAR and that the required submittal would affect the work of the licensee's engineering personnel on issues of perceived higher safety significance.

The NRC staff reviewed the licensee's request and granted the exemption, by letter dated April 11, 1985. However, the staff determined that only a six month exemption from compliance with 10 CFR 50.71 was warranted at that time. By letter dated September 13, 1985, the licensee requested an additional exemption from the schedular requirements of 10 CFR 50.71 for the submittal date of an updated FSAR. However, the NRC staff, by letter dated October 2, 1985, informed NNECO that this exemption request was not responsive to the terms identified in the exemption granted on April 11, 1985, and therefore, the exemption request was denied. The denial was based on the licensee's failure to supply the required milestones or schedules, but left open the possibility of further consideration by the staff provided the licensee took certain actions by October 11, 1985.

By letter dated October 11, 1985, NNECO resubmitted a request for an exemption to the schedular requirements of 10 CFR 50.71 for an updated FSAR. In that letter, NNECO stated that the FSAR update would be based largely on the format of Regulatory Guide 1.70, Revision 3, which would result in a more comprehensive document than would result from minimal compliance with 10 CFR 50.71. NNECO also provided milestones for the submittal of component parts of an updated FSAR and a completion schedule for the entire FSAR update.

An exemption until March 31, 1987 was granted by the staff by a letter dated November 22, 1985. According to the strict terms of that exemption, the schedule for the submittal of the FSAR update has been established and the work necessary to complete it will be carried on independent of ISAP. By letter dated December 17, 1986, NNECO submitted its first installment of the updated FSAR and by letter dated March 27, 1987, NNECO submitted the remaining chapters of the updated FSAR the requirements of the exemption. Therefore, Topic 1.15 is resolved.

3.3.16 Topic 1.16, Appendix R

Appendix R to 10 CFR 50, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," requires that licensees establish a fire protection program at their nuclear power plants. The program is to establish the fire protection capability for structures, systems and components important to safety, and develop the procedures, equipment and personnel required to implement the program.

NNECO, as a result of the review of proposed exemption requests submitted for Millstone Unit No. 1 for compliance with 10 CFR 50.48 and Appendix R to 10 CFR 50, identified four plant modifications to bring the plant into compliance with fire protection requirements. These modifications are:

(1) Provide capability to use a diesel generator from Millstone Unit No. 2 to supply emergency power to Millstone Unit No. 1 during a control room or turbine building fire and provide backfeed capability that would allow Unit 1 to supply Unit 2 with shutdown power for a Unit 2 control room fire.

(2) Modify the control rod drive pumps to operate without an external source of cooling water during a control room or turbine building/intake structure fire.

(3) Modify portions of the shutdown cooling system to allow the plant to be cooled to cold shutdown conditions without the use of service water.

(4) Protect the three drywell penetrations in the shutdown cooling pump cubicle that contain power and control cables to certain valves.

By letter dated November 6, 1985, the staff issued an exemption to certain requirements of 10 CFR Part 50, Appendix R, Section III.G.2, in response to the request by NNECO. The exemption was based, in part, upon the licensee's commitment to implement the four proposed modifications listed above.

NNECO, in a letter dated November 21, 1985, informed the staff that they had performed a revalidation and verification of the completeness and accuracy of their previous Appendix R submittals since the submittal of their original Appendix R review. NNECO stated that, as a result of their review, new fire areas were established and the corresponding fire boundaries were identified. The new fire analysis resulted in a request by NNECO, in a letter dated November 21, 1985, for new exemptions from the requirements of 10 CFR Part 50, Appendix R. NNECO stated that approval of the previous exemptions do not affect their new submittal. NNECO has stated that the four items to be evaluated in ISAP are still valid given the results of their Appendix R re-review. The November 21, 1985, exemption request mainly addresses the adequacy of existing fire barriers. In a letter dated March 3, 1986, the staff concurred on the licensee's proposed scope for this topic in the integrated assessment. The licensee's November 21, 1985 request for additional exemptions from 10 CFR Part 50 is currently under review by the staff and will be addressed outside the scope of ISAP.

In letters dated August 7 and August 26, 1985, NNECO submitted the PSA summaries for this topic. Only modifications (1) and (2) were evaluated in the PSA summaries.

The August 7, 1985, PSA summary investigated the benefit of providing emergency power from Millstone Unit No. 2 to Unit No. 1 to be able to provide a source of makeup water to the primary coolant during periods of extended loss of power. The backfeed power would be used to run the CRD pumps to supply makeup water. NNECO calculated that the core melt frequency would be reduced by approximately 5.5 E-5 per year.

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The staff review of the PSA summary for modification (1) found the benefits to be potentially larger than NNECO estimated. The fire in the switchgear room could be a more serious event than the analysis indicates. The staff agrees that this modification could achieve the estimated reduction in core melt frequency. This modification is also closely related to Topic 1.02, Tornado Missile Protection (refer to Section 3.2.2)

The August 26, 1985, PSA summary investigated a modification to the CRD pumps (modification (2)) to permit self-cooling in the event that service water is lost following a screenhouse fire. By itself this modification would have a public safety attribute score of 0 since it requires a backfeed power capability. Taken together, the backfeed capability and CRD pump self-cooling capability will have a public safety attribute score of 5 on a scale of -10 to +10. The staff has reviewed this scoring and finds the implementation priority for modification (1) to be high and for modification (2) to be low. However, since Millstone is a three unit site, the staff recommends that NNECO consider in their design of a backfeed system the benefit of adding backfeed capability to and from Millstone Unit No. 3 or the benefit of a dedicated diesel generator capable of supplying power to any of the three Millstone units. The benefits and disadvantages could be evaluated using the PSA.

In a letter dated July 31, 1986, NNECO identified 8 additional items to be included in the scope of the ISAP review. These 8 items are the result of their Appendix R revalidation and verification study. These items are:

(1) Curbs, ramps and seals;

(2) Water curtains/steel enclosures;

(3) Cable vault Halon suppression system;

(4) Control room Halon suppression system;

(5) Fire barriers;

(6) MSIV/ADS circuit protection;

(7) Hydrogen system modifications; and

(8) Emergency lighting modifications.

(Refer to the NNECO July 31, 1986 letter for more detail on these 8 items).

The staff has reviewed the attribute scores for all twelve items in Topic 1.16 and finds the relative priority of the items to be appropriate as identified in Table 4-1. Also, by letter dated September 10, 1986, NNECO stated that all modifications required to be completed by August 6, 1986 were completed and that modifications which must be made during an extended outage will be made during the 1987 refueling outage.

3.3.17 Topic 1.17, Replacement of Motor Operated Valves

10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," requires that the environmental qualification program at Millstone Unit No. 1 be completed at the end of the second refueling outage following March 31, 1983. The staff granted an extension of the completion date to November 30, 1985 for 28 valve motor operators. These operators were the only components yet to be qualified to achieve compliance with 10 CFR 50.49. By letters dated September 30, 1985 and October 16, 1985, NNECO stated that, upon further evaluation, eleven valve motor operators would be replaced by the end of the 1985 Millstone Unit No. 1 refueling outage (before November 30, 1985), exemption requests for six valves have been submitted and that the remaining eleven valves would require schedule extension requests so that they may be evaluated during the ISAP review.

On November 20, 1985, the Commission issued a Memorandum and Order to NNECO regarding the deadline for environmental qualification of electric equipment at Millstone Unit No. 1. The subject of the Memorandum and Order was the Commission's decision regarding the eleven valve motor operators for which NNECO requested a schedular exemption. The Commission approved an extension of the schedule to the next outage of sufficient duration after the staff has made a determination on whether an exemption to 10 CFR 50.49 can be granted, or to the next refueling outage, but in no case later than August 30, 1987.

By letter dated December 18, 1985, the staff issued an evaluation that found the six valve motor operators for which a permanent exemption was requested to be outside the scope of equipment to be environmentally qualified. Therefore, an exemption for these six motor operators was not necessary.

NNECO's proposed scope for this topic is to evaluate the safety and risk aspects associated with the environmental qualification of the remaining eleven valve motor operators. By letter dated January 17, 1986, NNECO submitted a request for exemption for the eleven valve motor operators based on the criteria of 10 CFR 50.12. Four of the eleven valves (valves 1-LP-15A and B, 1-LP-16A and B) are the drywell spray valves which are located in the containment spray line and provide isolation to prevent inadvertent spraying of the drywell. Two valves (1-IC-2, 1-IC-4) are the isolation condenser steam inlet isolation and condensate return valves. They are two of the four isolation condenser primary side isolation valves (the other two isolation condenser isolation valves are already qualified). Two valves (1-CU-2, 1-CU-3) are in the reactor water cleanup system (RWCU) and serve as the inboard and outboard isolation valves on the RWCU suction line. Two valves (1-RR-2A and B) are used to isolate the low pressure coolant injection system from a break in the recirculation pump piping. The last of the eleven valves (1-MW-96A) is an isolation valve between the main condenser hotwells and the condensate storage tank (CST).

By letter dated March 12, 1987, NNECO withdrew their request for exemption for valves 1-RR-2A and B and stated that they plan to environmentally qualify these values during the 1987 refueling outage.

In a letter dated October 17, 1985, NNECO submitted the PSA summary for this topic. The PSA summary investigated the reduction in core melt frequency and public risk if the modifications for environmental qualification for the eleven valves are implemented. For some of the valves, the public safety attribute was evaluated by performing sensitivity studies on the PSA Interfacing System LOCA analysis (Method A). The remaining valves were not amenable to direct numerical calculations and therefore, engineering judgement based on insights from the PSA was utilized in assessing the benefit (Method B).

The staff has this information under review and is expected to issue an SER on the exemption request in April. The position taken by the staff in that SER should be used by the licensee in developing the integrated schedule. The staff recommends a high implementation priority for any plant modifications which may still be required. The staff's review conclusions and the licensee's comments on this topic will be presented in the final ISAR.

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3.3.18 Topic 1.18, ATWS

GDC 20 requires that nuclear power plants be provided with a protection system which will automatically initiate the operation of appropriate systems to ensure that specified fuel design limits are not exceeded as a result of anticipated operational occurrences and sense accident conditions and initiate the operation of systems and components important to safety. Section 50.62 of 10 CFR 50 was promulgated to require additional protection against an anticipated transient without scram (ATWS), an anticipated operational occurrence followed by a failure of the protection system to shutdown the reactor.

As stated by NNECO in letters dated August 13 and September 9, 1985, Millstone Unit No. 1 is currently in compliance with the requirements of 10 CFR 50.62 regarding alternate rod insertion and recirculation pump trip systems. However, as documented by NNECO, Millstone Unit No. 1 is equipped with a Standby Liquid Control System (SLCS), but its capacity (43 gpm 13 weight percent sodium pentaborate solution) does not meet the requirements of 10 CFR 50.62. NNECO plans to evaluate the significance of this difference and perform an assessment of the need to increase the SLCS capacity in the integrated assessment. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated August 23, 1985, NNECO provided the PSA summary for this topic. The PSA summary evaluated the relative merit of increasing the SLCS capacity from its present flow rate of 43 gpm to 86 gpm as required by 10 CFR 50.62. The 43 gpm capacity case was modeled such that a core melt was assumed to occur if the operator failed to take proper action. The 86 gpm capacity case was modeled such that a core melt was assumed to occur if the operator failed to take proper action and the SLCS failed. The result of this comparison of cases was a reduction in core melt frequency of 6 E-6 per year.

The staff evaluation of the PSA summary for this topic found the staff not agreeing with the licensee's evaluation of ATWS events. This disagreement is discussed in detail in Section 3.3 of Appendix C. Therefore, the staff found it necessary to perform its own analysis for this topic. This analysis is discussed in detail in Section 4.12 of Appendix C. The staff calculated that the maximum potential core-melt frequency reduction from the installation of an 86 gpm capacity SLCS is about 3E-6 per year.

At a meeting on August 21, 1986, between NNECO and the staff, NNECO stated that an analysis of ATWS, considering the unique features of the Millstone Unit No. 1 plant design, would likely provide justification for an exemption from the 86 gpm SLCS requirement. However, since the cost of the ATWS analysis and the cost of upgrading to an equivalent 86 gpm SLCS

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system (the present 43 gpm capacity injection system together with a higher concentration boron solution using B-10) are comparable and because there is no NRC approved methodology for such an analysis, NNECO stated that they were investigating compliance with the rule using the enriched boron solution.

By letter dated September 11, 1986, NNECO stated that they will comply with the SLCS by using an enriched boron solution. This compliance is dependent only on the purchasing and delivery schedule for B-10 and on plant availability to change the sodium pentaborate solution to the B-10 solution. The staff finds this commitment adequate to resolve this topic and ranks this as a medium implementation priority.

3.3.19 Topic 1.19, Integrated Structural Analysis

As part of the Millstone Unit No. 1 SEP review (Topics II-3.B, II-4.F, III-3, III-6 and III-7.B), components and structures were evaluated with regard to structural adequacy under various loading conditions. As documented in the IPSAR Supplement, some issues still remain to be resolved. These issues are:

(1) II-4.F - pile/soil interaction, turbine building evaluation
(2) III-3.A - groundwater, flooding
(3) III-3.B - flooding, masonry walls
(4) III-6 - seismic considerations
(5) III-7.B - load combinations and code changes

In a letter dated October 7, 1985, the staff issued a safety evaluation in which the method to achieve safe shutdown in the event of flooding is resolved if it can be shown that the block walls of the fire pump house are adequate to resist flood loads. Also, the staff concluded that additional analyses should be conducted to confirm the margins of safety for all Category I structures for loading conditions in combination with groundwater. The staff recommended that these analyses be considered in ISAP. In a letter dated October 16, 1985, NNECO proposed to consolidate these structural issues and address them in ISAP. NNECO has submitted information concerning the open issues.

In a letter dated March 3, 1986, the staff concurred on the proposed scope for this topic and stated that NNECO should consider the resources necessary to complete these open items and possible plant modifications in the integrated assessment. The staff is currently preparing an SER for the outstanding open items in SEP Topic II-7.B. The staff has tentatively identified four issues that are still open and will require the licensee to provide additional information. These issues are:

(1) Compression Members - The web of most standard tee sections, when used as a compression member, does not meet the current AISC Code requirements, i.e., buckling of the member would be expected. The licensee evaluated this issue by evaluating selected samples of compression members. The staff found the sampling approach to be an acceptable method of resolving this issue. However, the sampling procedures, sampling basis, sample size, details of evaluation and

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basis for the licensee's conclusions were not submitted for staff review. The licensee's submittal did demonstrate that one of the sample members did not meet the code requirements.

It is the staff's position that the licensee should either expand the sample size to demonstrate that the remaining standard tee section compression members will satisfy the code requirements or demonstrate that the failure of these members will not degrade the safety margins of structures.

(2) Coped Beam Connections - The licensee evaluated the significance in the code changes for shear load capacity of coped beam connections. Based on the calculations the licensee determined that all of the bolted or riveted beam connections in the plant where the top flange or both flanges of steel beams were coped are adequate for the new code provisions. Since none of the calculations were submitted for review, it is the staff's understanding that the AISC standard maximum uniform load tables were used by the licensee. In order to resolve this open item, the licensee should calculate the most severe shear loads imposed on the beams in the actual service condition and evaluate the adequacy of the connection.

(3) Columns with Spliced Reinforcements - NNECO presented a discussion of the fatigue environment of concrete columns in Seismic Category I buildings and expressed the opinion that fatigue usage would be found small and concluded that column reinforcement splices designed to ACI 318-63 Code will be adequate for alternating stresses. It is the staff's position that the licensee's conclusion is not acceptable. The licensee should demonstrate the adequacy of the column splices for the most severe load reversal either by using the existing test data or by calculation.

(4) Containment Penctration Bellows - In the evaluation of the containment penetration bellows assemblies X-7A through 7D, the staff raised two concerns. The first concern was the procedure used in evaluating the bellows assemblies was acceptable provided that the testing requirements of NE-3365.2(e)91) of the 1983 ASME Code, to ensure the validity of the calculations, have been met. It is the staff's position that NNECO should provide information sufficiently detailed to determine that the requirements as to number, type and outcomes of the tests have been met. The second concern was the lack of information on a seismic load evaluation of the bellows assemblies. It is the staff's position that this information should be submitted and should consider the effects of the relative displacements of the bellows assembly ends resulting from the seismic response of the attached components and the effect of simultaneous direct seismic responses of the bellows.

The last open issue in Topic 1.19 deals with pile/soil interactions. The remaining items concern the load carrying capability of the foundation piles during a SSE event for the turbine generator building and the gas turbine building; the adequacy of the pile embedments at the TGB and GTB foundation/component interface; and the potential for liquification of soil under the GTB and consequent building settlement during a SSE event.

In a letter dated October 16, 1985, NNECO submitted information to resolve these open issues. Based upon the assumptions made, NNECO analyses showed that these issues have been resolved. The staff review of this information raised questions on the adequacy of NNECO's assumptions on peat materials and backfill amounts. The staff and the licensee have discussed these questions and the licensee has agreed to submit the information necessary to resolve this issue. The staff will present the results of its review in the final ISAR.

The staff concludes that the remaining open items in this topic, when resolved, would result in moderate reduction in CMF. Therefore, the completion priority for this topic should be medium.

3.3.20 Topic 1.20, MOV Interlocks

10 CFR 50.55a(h), as implemented by Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971 and 10 CFR 50 (GDC 13, 21, 22, 23, and 29), requires that protective actions be reliable and precise and that they satisfy the single failure criterion using quality components. Regulatory Guide 1.106 presents the staff position on how thermal-overload protection devices can be made to meet these requirements.

As documented in IPSAR Section 4.14, the staff found that, of 59 safety-related motor-operated valves (MOVs), 12 are not normally in their emergency position and have thermal-overload protection devices that are not bypassed by an emergency signal nor has it been shown that their trip setpoints were conservatively set. The licensee proposed to analyze the trip setpoints and modify, where necessary, thermal overload protection devices. The analysis was to include a demonstration that proper thermal overload protection devices have been selected, that their trip setpoints have been conservatively set and a summary of the operating experience for each of the 12 valves.

By letter dated August 13, 1985, NNECO provided an assessment of this issue. As discussed in the safety evaluation dated September 16, 1985, the staff concluded in the IPSAR Supplement that the thermal overload setpoints have been conservatively established such that there is reasonable assurance the valves will operate under accident conditions. Therefore, this issue is resolved.

3.3.21 Topic 1.21, Fault Transfers

As part of the Millstone Unit No. 1 SEP review (Topic VI-7.C.1), the AC and DC power systems were reviewed against the criteria of GDC 2, 4, and 18, as implemented by SRP Sections 8.2 and 8.3 and Regulatory Guide 1.6, to ensure that the onsite electrical power supplies and distribution systems have sufficient independence to perform their safety function assuming a single failure. As documented in the IPSAR supplement, all of the issues raised in the SEP review were resolved except for the

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design of the automatic bus transfer devices and the need for interlocks on three load centers that are manually transferred between redundant sources.

By letter dated October 16, 1985, NNECO stated that the 480 VAC motor control center EF-7 has been disarmed and cannot automatically transfer loads of one load group to the power source of another load group. DC motor control centers DC-IIA-1, 2, and 3 are each provided with manual transfer switches which are administratively controlled. The feeder breaker from the alternate DC source to the transfer switch is kept open (de-energized). The remaining six automatic bus transfers were reviewed by NNECO. NNECO found that disarming or removal of the devices was not practical due to the safety function of the devices.

In a letter dated September 6, 1985, NNECO submitted the PSA summary for this topic. The PSA summary investigated the impact of using the six remaining automatic bus transfers (ABT). NNECO stated that the transformers that provide normal and emergency power to the IAC-1 and VAC-1 switchboards are being replaced with regulating transformers to provide isolation between the redundant feeds by limiting the fault current to 150% of normal full load. The transformer load side feeder breakers will be fitted with ground detection devices that will trip before the 480 VAC breaker is tripped thermally. The frequency of breaker challenge for the two buses is 1.1E-6 per year. This frequency is three orders of magnitude less than the estimated frequency of station blackout due to a loss of normal power and loss of onsite power event. NNECO concluded that the use of these ABTs will not significantly impact the probability of losing both sources of power.

The staff review of the PSA analysis for these two buses concluded that the analysis of the potential for the transfer of an electrical fault from one power supply to another via IAC-1 and VAC-1 ABTs provides an accurate representation of the potential risks associated with the use of these ABTs.

The remaining four ABTs are installed on motor control centers EF-3 and FE-3 and provide redundant motive and control power sources for the motor operated injection valves on each LPCI loop. The PSA summary investigated only the removal of these four ABTs and not their replacement. If the ABTs were disarmed, then some other method for providing redundant power would have to be developed. One way to accomplish this would be to provide redundant injection pathways on each LPCI loop. However, the impact of the addition of the redundant injection piping system was not investigated. NNECO analysis showed an increase in public risk with an associated public safety attribute score of -0.25 on a scale of -10 to +10.

The staff review of the PSA analysis for these four ABTs found that NNECO's analysis of the impact of the use of ABTs to supply power to the injection valves for the LPCI system appears to overestimate the impact of the removal of the ABTs while not estimating the potential negative impact resulting from their use.

If the ABTs are removed from the LPCI system the reliability of the system will be reduced for those support states where one electrical bus is available. There are 22 accident sequences in the PSA that include a failure of the LPCI system in the injection mode. When these sequences are requantified using the revised system unavailabilities, the total core melt frequency increases by approximately 4E-7 per year, which is not a significant increase. However, if the LPCI system is modified so that redundancy exists when the system is operated in the alternate shutdown cooling mode, the removal of these ABTs could have a greater impact on the core melt frequency. The staff rates the implementation priority for this topic as medium.

3.3.22 Topic 1.22, Electrical Isolation

As part of the Millstone Unit No. 1 SEP review (Topic VII-1.A), the isolation of the reactor protection system was reviewed against the criteria of 10 CFR 50.55a(h), as implemented by IEEE Std. 279-1971, to ensure that safety signals are isolated from non-safety signals and that no credible failure at the output of an isolation device can prevent the associated protection system channel from meeting the minimum performance requirements.

As documented in the IPSAR supplement, the staff found that there were no isolation devices between the nuclear flux monitoring systems and the process recorders and indicating instruments, nor were there any isolation devices between the average power range monitor and the process computer.

By letter dated January 31, 1985 (summarized in a letter dated October 16, 1985), NNECO submitted additional information regarding these two open items.

The staff has this information currently under review. The preliminary conclusions are that there will be only a small probability of the necessity for plant modifications. However, there will probably be some additional information required. The staff rates the overall implementation priority for any yet to be determined actions by NNECO as low. This ranking is consistent with that proposed by NNECO.

3.3.23 Topic 1.23, Grid Separation Procedures

Topic 1.23 has been integrated into related Topic 1.25, Degraded Grid Voltage Procedures. Refer to Section 3.3.25 for the evaluation of these topics.

3.3.24 Topic 1.24, Emergency Power

As part of the Millstone Unit No. 1 SEP review (Topic VIII-2), the emergency power sources were reviewed against the criteria of GDC 17, as implemented by SRP Section 8.3.1, with regard to preventive maintenance programs for the gas turbine generator. As documented in the IPSAR supplement, NNECO was to review its preventive maintenance program for the gas turbine generator to identify areas for improvement because operating experience at Millstone Unit No. 1 and PSA perspectives indicated that one-quarter of the dominant accident sequences involved gas turbine failure.

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The licensee responded by letters dated May 10, 1983 and June 20, 1983. In these responses, the licensee proposed changes in the preventive maintenance program regarding the engine mounted fuel pump, fuel shutoff valve, air start regulating valve, air receiver and control circuit timers. Subsequently, by letter dated June 12, 1984, NNECO stated that both the engine-mounted fuel pump and fuel shutoff valve had been replaced in 1976 and upon advice of the engine manufacturer, NNECO will inspect these components at the frequency recommended by the manufacturer.

In addition to the changes in the preventive maintenance program recommended by the staff, NNECO has made hardware modifications to increase reliability of the GTG. By letter dated August 16, 1984, the staff concluded that the revised maintenance program acceptably resolved this issue.

As detailed in IE Inspection Report 50-245/86-01 dated April 14, 1986, the GTG failed to start during a surveillance test on January 9, 1986. Although subsequent maintenance and testing appeared to resolve the problem, problems persisted until January 20, 1986. Satisfactory emergency starts were conducted on January 20, 21, 22, 24, 28 and February 4. All of these starts exhibited normal characteristics and NNECO returned to a normal surveillance frequency. The IE Inspection Report concluded that additional measures may be needed to assure improved GTG reliability.

During a March 12-14, 1986, meeting on the Millstone Unit No. 1 ISAP, the staff requested NNECO to further investigate possible preventive maintenance practices that could help to reduce the GTG failure rate. Due to the close relationship of this topic to Topic 1.01, Gas Turbine Generator Start Logic Modifications, NNECO and the staff analyzed the risk impacts of the two topics concurrently. Refer to Section 3.3.1 for details on the PSA summary review for this topic.

In an effort to better address the issue of station blackout at Millstone Unit 1, the staff has expanded the scope of this topic.

The staff recognizes NNECO's efforts to monitor and improve the reliability of the GTG. The gas turbine is among the best monitored systems at Millstone Unit 1. However, a gas turbine used as a source of emergency power is a very complex piece of machinery used in a more demanding situation than envisioned by its designers, and requires a high degree of proficiency in its maintenance.

The staff recommends that NNECO bolster its program for maintaining and monitoring the GTG by:

(1) acquiring state-of-the-art data collection equipment;
(2) continue to monitor all significant performance parameters;
(3) improving the component/system tests to more completely test component system functions and responses to actual demands made during transient conditions;

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(4) increasing the NNECO staff knowledgeable about gas turbines and increasing the training of those already in the program.

The staff rates the contributions of these recommendations to decreasing the probability of station blackout as medium. Refer to Section 3.4.1 for a more detailed discussion of station blackout.

3.3.25 Topic 1.25, Degraded Grid Voltage Procedures

As part of the Millstone Unit No. 1 SEP review (Topics VII-3 and VIII-1.A), the power supply system was evaluated against the criteria of GDC 17, with regard to the ability of the plant to cope with degraded grid voltage. If the grid voltage were to degrade and become low enough so that the voltage at the Class 1E equipment is less than its qualified operating voltage, equipment damage could occur.

In a letter dated October 9, 1985, NNECO submitted interim degraded grid voltage procedures that would be implemented pending completion of the Millstone Unit No. 1 design modifications. The design modifications, identified as Millstone Unit No. 1 Item 3 in the staff's July 31, 1985 letter on ISAP issues, were scheduled to be completed during the 1985 refueling outage. Final degraded grid voltage procedures were to be developed following the implementation of the modifications. The original scope of the ISAP topic was to submit interim procedures to the staff and then develop a priority for the final procedures in the integrated assessment.

By letter dated November 14, 1985, NNECO stated that it had reviewed the proposed design changes using the Millstone Unit No. 1 PSA to evaluate their impact on plant safety. NNECO found that the chance of a station blackout following a loss of the switchyard would be approximately 2.4 times greater with the new design than with the existing undervoltage protection due to a loss in the redundancy in actuation signal function when two power train logic system schemes are separated. The application of PRA methods, having identified the increased probability of a station blackout, led NNECO to the determination that the design change would not be prudent until the design can be refined. As a result, NNECO proposed postponing the design modification until the 1987 refueling outage. By letter dated December 12, 1985, the staff found the licensee's change of schedule to be acceptable, although the staff required additional information to confirm that the adverse impact of completing the degraded grid voltage modifications outweighs the intended benefits of the improvements. By letter dated May 20, 1986, the staff concluded that the interim degraded grid voltage procedures are acceptable until the final degraded grid protection modifications are completed during the 1987 refueling outage.

By letter dated January 13, 1986, NNECO provided a description of the probabilistic assessment results and the design analysis of the degraded grid protection modifications which were to have been implemented. In a letter dated March 3, 1986, the staff concurred on the proposed change of scope for this topic.

While NNECO has not made an ARM score for this topic the staff rates the implementation of this issue as medium. This issue is one of several contributors to the Station Blackout issue. This implementation priority ranking is consistent with NNECO's commitment to make the design modification during the 1987 refueling outage.

3.3.26 Topic 1.26, Equipment Classification/Vendor Interface (GL 83-28, Item 2.1)

NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, required licensees to: (1) confirm that all components whose functioning is required to trip the reactor are identified as safety-related in documents, procedures and information handling systems used in the plant for controlling safety-related activities, including maintenance, work orders and parts replacement and (2) establish, implement and maintain a continuing program to ensure that vendor information is complete, current and controlled throughout the life of the plant, and appropriately referenced or incorporated in plant instructions and procedures.

By letter dated September 9, 1985, NNECO stated that at Millstone Unit No. 1, components required for reactor trip are identified as safety-related in documents, procedures and information handling systems used in the plant to control safety-related activities. These components are currently identified on the Category 1 Material, Equipment and Parts List (MEPL) and will be identified on the Production Maintenance Management System (PMMS) data base, which will replace the document form of the MEPL.

Details on the PMMS and other information on this issue were submitted by NNECO by letters dated November 8, 1983 and May 9, 1985.

By letter dated November 24, 1986, the staff issued an SER for Part 1 of the requirements of GL 83-28, Item 2.1 (Equipment Classification). The staff stated that a program exists for identifying, classifying and treating components that are required for performance of the reactor trip function as safety related. This part of Topic 1.26 is resolved. In the same letter the staff requested additional information to resolve Part 2 (Vendor Interface) of this topic. The staff rates the implementation priority for the possible information request to be low since the resolution of this topic will have no effect on the overall CMF for Millstone Unit No. 1.

3.3.27 Topic 1.27, Post-Maintenance Testing Procedures (GL 83-28, Items 3.1.1 and 3.1.2)

NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, required licensees to submit the results of their review of test and maintenance procedures and technical specifications to assure that post-maintenance operability testing of safety-related components in the reactor trip system is required to be conducted and that the testing demonstrates that the equipment is capable of performing its safety functions before being returned to service. Also, licensees were required to submit the results of their check of vendor and engineering recommendations to ensure that any appropriate test guidance is included in the test and maintenance procedures and technical specifications, where required.

By letter dated September 9, 1985, NNECO stated that a review of the Millstone Unit No. 1 test and maintenance procedures and technical specifications indicated that post-maintenance operability testing is required in all cases. Also, all known applicable vendor and engineering recommendations regarding testing have been included in test and maintenance procedures. This information and information submitted by letter dated November 8, 1983, was reviewed by the staff and by letter dated February 21, 1986, the staff concluded that the licensee complied with Items 3.1.1 and 3.1.2 of Generic Letter 83-28. Therefore, this issue is resolved.

3.3.28 Topic 1.28, Post Maintenance Testing TS Changes (GL 83-28, Item 3.1.3)

NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, required licenses to identify, if applicable, any post-maintenance test requirements in existing technical specifications which can be demonstrated to degrade rather than enhance safety. Appropriate changes to those test requirements should be submitted for staff review and approval.

By letter dated November 8, 1983, NNECO provided a response to Item 3.1.3 of Generic Letter 83-28. In that response, no technical specification requirements for post-maintenance testing were identified which will result in degraded safety of the reactor trip system or other safety-related components. The licensee has committed to continuously review incoming vendor information and engineering recommendations with respect to impact on component reliability. Should the potential for degradation of safety due to post-maintenance test requirements be identified, the licensee will submit appropriate technical specification changes and justification for NRC approval.

In a letter dated September 3, 1985, the staff issued a safety evaluation for this topic in which the staff concluded that the licensee's response to Item 3.1.3 was acceptable and that their commitment to review new information with regard to this item provides additional assurance that the Millstone Unit No. 1 technical specifications will continue to provide a basis for safe plant operation.

On the basis of the September 3, 1985 safety evaluation, this topic is resolved.

3.3.29 Topic 1.29, Response to Generic Letter 81-34

On August 31, 1981, the staff sent Generic Letter 81-34 to BWR licensees wherein plant-specific responses conforming to the guidance contained in NUREG-0803, "Generic SER Regarding Integrity of BWR Scram System Piping," were requested. The NUREG-0803 guidelines essentially addressed the need for improvement in procedures, periodic inservice inspection and surveillance for the scram discharge volume, and environmental qualification for essential equipment needed for mitigation of the consequences of postulated pipe failures in the scram system piping. These guidelines were developed to address the consequences of a postulated crack in the system piping resulting in large leakage downstream of the isolation valves. The scope of Topic 1.29 was to respond to the requirements of Generic Letter 81-34.

By letter dated September 13, 1985, NNECO augmented the response to Generic Letter 81-34. NNECO stated that the scram discharge volume system was modified in 1982 to replace all piping downstream of the hydraulic control unit header and the single scram discharge volume was replaced by two larger volumes. The new piping meets the design, fabrication, installation, testing and quality assurance requirements of the American Society of Mechanical Engineers (ASME) Code, Section III Class 2 components. The piping and supports were designed to seismic Category I criteria. Also, NNECO participated in the BWR Owners Group efforts to address the concerns of NUREG-0803.

By letter dated January 3, 1986, the staff forwarded Generic Letter 86-01 to all BWR applicants and licensees. In that generic letter the staff concluded that (1) through wall leakage cracks or breaks do not need to be postulated; (2) the scram discharge volume piping system leakage from a flaw will not give rise to a harsh environment so that no additional environmental qualification of equipment is necessary; (3) revised BWR Owners Group Emergency Procedure Guidelines, together with normal plant procedures and the proposed visual verification of piping integrity, are sufficient measures for detecting and mitigating system leakage, and (4) water hammer is not a contributing factor in potential system breaks.

On the basis of the Generic Letter 86-01 findings, NNECO's scram discharge volume system modifications, NNECO's participation in the BWR Owners Group on this issue and the plant specific features of Millstone Unit No. 1, the staff considers this issue resolved.

3.3.30 Topic 1.30, Post-Trip Review Data and Information (GL 83-28, Item 1.2)

NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, requires licensees to prepare a report which describes and justifies the adequacy of equipment for diagnosing an unscheduled reactor shutdown. The report, as a minimum, should describe: (1) the capability for assessing sequence of events; (2) the capability to determine the cause of functioning of safety-related equipment; (3) other data and information provided to assess the cause of the shutdown; and (4) the schedule for any planned changes to existing data and information capability.

By letter dated September 9, 1985, NNECO stated that the plant process computer is currently scheduled for replacement (see related Topic 2.03, Section 3.2.55). In a letter dated November 6, 1985, the staff provided a draft report representing the staff's initial judgement of NNECO's response to Generic Letter 83-28, Item 1.2. In response to a request for additional information, NNECO submitted information on Item 1.2 on January 10, 1986. In a letter dated June 24, 1986, the staff issued the SER for this topic and concluded that the post-trip data and information capabilities at Millstone Unit No. 1 are acceptable. Therefore, the staff considers this issue resolved.

3.3.31 Topic 1.31, Equipment Classification/Vendor Interface (GL 83-28, Item 2.2)

NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, requires licensees to describe their program for ensuring that all components of safety-related systems necessary for accomplishing required safety functions are identified as safety-related on documents, procedures and information handling systems used in the plant to control safety-related activities. Also, licensees were required to establish, implement, and maintain a continuing program to ensure that vendor information is complete, current, and appropriately referenced or incorporated in plant instructions and procedures.

By letter dated September 9, 1985, NNECO stated that they have established criteria to identify systems, structures and components which are safety-related. The information handling system used to identify these items is the Category 1 MEPL.

The licensee's submittal is currently under review by the staff. It is not anticipated that any plant modifications will result from the staff review. By letter dated October 22, 1986, the staff requested additional informtion related to this topic and a schedule for providing the information. The staff rates the implementation priority for the information request to be low since the resolution of this topic will have no effect on the overall CMF for Millstone Unit No. 1.

3.3.32 Topic 1.32, Post-Maintenance Testing Procedures (GL 83-28, Items 3.2.1 and 3.2.2)

NUREG-1000, "Generic Implications of ATWS Events at Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, requires licensees to submit the results of their review of maintenance procedures and technical specifications to assure that post-maintenance operability testing of safety-related components in the reactor trip system is required to be conducted and that the testing demonstrates that the equipment is capable of performing its safety functions before being returned to service. Also, licensees were required to submit the results of their check of vendor and engineering recommendations to ensure that any appropriate test guidance is included in the test and maintenance procedures or technical specifications, where required.

By letter dated September 9, 1985, NNECO stated that post-maintenance operability testing is required in all cases. All known applicable vendor and engineering recommendations regarding testing have been included in test and maintenance procedures. No recommendations were applicable to the technical specifications. This information and information submitted by letter dated November 8, 1983, has been reviewed by the staff. By letter dated February 21, 1986, the staff concluded that this item is resolved.

3.3.33 Post Maintenance Testing TS Changes (GL 83-28, Item 3.2.3)

NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, required licensees to identify, if applicable, any post-maintenance test requirements in existing technical specifications which can be demonstrated to degrade rather than enhance safety. Appropriate changes to those test requirements should be submitted for staff review and approval.

By letter dated November 8, 1983, NNECO provided a response to Item 3.2.3 of Generic Letter 83-28. In that response, no technical specification requirements for post-maintenance testing were identified which will result in degraded safety of the reactor trip system or other safety-related components. The licensee has committed to continuously review incoming vendor information and engineering recommendations with respect to impact on component reliability. Should the potential for degradation of safety due to post-maintenance test requirements be identified, the licensee will submit appropriate technical specification changes and justification for NRC approval.

In a letter dated September 3, 1985, the staff issued a safety evaluation for this topic in which the staff concluded that the licensee's response to Item 3.2.3 was acceptable and that their commitment to review new information with regard to this item provide additional assurance that the Millstone Unit No. 1 technical specifications will continue to provide a basis for safety plant operation.

On the basis of the September 3, 1985 safety evaluation, this topic is resolved.

3.3.34 Topic 1.34, Reactor Trip System Testing (GL 83-28, Items 4.5.2 and 4.5.3)

NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, requires licensees to justify not making modifications to permit on-line testing of the trip system, if the plant is not currently designed to permit such testing. Also, licensees were required to review existing intervals for on-line functional testing required by technical specifications to determine that the intervals are consistent with achieving high reactor trip system availability.

By letter dated September 9, 1985, NNECO stated that since on-line testing is performed at Millstone Unit No. 1, Item 4.5.2 is not applicable. Also, NNECO intends to endorse the BWR Owners Group response to Item 4.5.3.

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This information is currently under review by the staff. It is not anticipated that any plant modifications will result from the staff review, however, it is possible that additional information may be requested from NNECO. The staff rates the implementation priority for the possible information request to be low since the resolution of this topic will have no effect on the overall CMF for Millstone Unit No. 1.

3.3.35 Topic 1.35, Reactor Trip System Functional Testing (GL 83-28, Item 4.5.1)

NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," as implemented by Generic Letter 83-28, Item 4.5.1, requires licensees to perform on-line functional testing of the reactor trip system including independent testing of diverse trip features.

By letter dated September 9, 1985, NNECO stated that on-line functional testing of the Millstone Unit No. 1 reactor trip system is performed at frequencies defined by the technical specifications. A procedure to fully test the normal and ATWS back-up scram valves is being implemented in response to this item. This information and information submitted by letter dated November 8, 1983 has been reviewed by the staff. By letter dated February 21, 1986, the staff concluded that this item is resolved.

3.3.36 Topic 1.36, Technical Specifications Covered by Generic Letter 83-36

As part of the generic requirements of the TMI Action Plan, identified in NUREG-0737 and as implemented by Generic letter 83-36, all licensees of boiling water reactors were to provide technical specifications for assurance that facility operation is maintained within the limits determined acceptable following implementation at each facility.

By letter dated October 15, 1985, NNECO provided a status of each of the items in the enclosure to Generic Letter 83-36 for Millstone Unit No. 1. The October 15, 1985 submittal stated NNECO's position that Technical Specifications would not be submitted for Items II.B.3 and II.F.1.2. NNECO's position on these items has been evaluated and a determination made that commitment dates should be determined for submitting the subject Technical Specifications. NNECO's justification for stating that Technical Specifications are not warranted for Items II.B.3 and II.F.1.2 is inadequate as no plant specific justification is presented. Restating that Millstone, Unit No. 1, has in place the NUREG-0737 requirement on training, sampling and analysis, and provisions for maintenance of sampling and analysis equipment, does not provide assurance via technical specifications (TS) that facility operation is maintained within the limits determined acceptable following implementation, as required by Generic Letter 83-36.

The staff guidance of Generic Letter 83-36 for Technical Specifications was written with the knowledge that NUREG-0737 requirements would already have been met (e.g., equipment, procedures, personnel requirements). Therefore, just meeting the NUREG-0737 requirements does not constitute a valid basis for arguing that Technical Specifications are not

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warranted. Also, NNECO's other statements are inappropriate regarding "No concurrent enhancement of public health and safety, since the post-accident sampling system is not required for safe shutdown," and "referencing these items in the Technical Specifications would only serve to increase the size and complexity of the Technical Specifications." The staff was well aware of these considerations when the guidance for TSs in Generic Letter 83-36 were issued.

NNECO committed to Technical Specifications for Items II.B.3, II.F.1.2, II.F.1.3, II.F.1.4, II.F.1.5, II.F.1.6, and III.D.3.4, but did not propose any schedule for completion. The schedule for completing and implementing these Technical Specifications should be determined by the licensee, in accordance with our recommended low implementation priority, and incorporated in the integrated implementation schedule.

3.3.37 Topic 1.37, Technical Specification Changes to Address 10 CFR 50.72 and 50.73

On January 1, 1984, revisions to 10 CFR 50.72 and 50.73 became effective. Licensees were required by Generic Letter 83-43 to propose revisions to their technical specifications to address the revised reporting requirements in the regulations. By letter dated July 9, 1985, NNECO submitted proposed changes to the Millstone Unit No. 1 Technical Specifications to address 10 CFR 50.72 and 50.73. This information has been reviewed by the staff and the staff concluded that the Technical Specification changes proposed by the licensee are acceptable. The staff's conclusions were presented in an SER attached to Amendment 1 to the Millstone Unit No. 1 Technical Specifications issued on January 29, 1987. This topic is resolved.

3.3.38 Topic 1.38, Expand QA List

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.38. (TMI Action Plan Item I.F.1)

NUREG-0660, the TMI Action Plan, identified systems important to safety at TMI Unit 2 that were not designed, fabricated and maintained at a level equivalent to their safety importance. The NRC proposed to develop guidance for licensees to expand their Quality Assurance (QA) lists to cover equipment important to safety and rank the equipment in order of its importance to safety. The results of the Interim Reliability Evaluation Program and the systems interaction tasks would be used to establish the importance of equipment as it relates to safety. Experience in use of the revised NRR review procedure for developing QA lists for individual operations license applicants would also be factored into the generic guidance.

By letter dated October 16, 1985, NNECO presented information regarding the classification of structures, systems and components in the Millstone Unit No. 1 QA program. NNECO stated that structures, systems and

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components at Millstone Unit No. 1 are categorized into two groups, safety related equipment and non-safety related equipment and, as such, their QA program is a two-tier program.

NNECO stated that further expansion of the QA program or redefinition of QA program categories is unnecessary at Millstone Unit No. 1. Non-safety related structures, systems and components are routinely evaluated for their impact upon safety related equipment. The licensee contends that several recent licensing issues (e.g., environmental qualification and block walls) substantiate this statement. In those cases where the General Design Criteria in 10 CFR 50, Appendix A, are applicable, NNECO interprets the regulations to require that any non-safety related structure, system or component that could restrict safety related structures, systems, or components from performing the function necessary to comply with the particular GDC would need to be designed to preclude that restriction.

NNECO stated that management routinely applies accepted codes and standards to plant backfit projects involving non-safety related equipment. Design, installation and maintenance activities are subject to measures to ensure the quality of that equipment. The Millstone Unit No. 1 maintenance program addresses all plant equipment, not just safety related equipment. Based on the degree of attention given to non-safety related equipment at Millstone Unit No. 1, NNECO does not believe that a measureable increase in safety would be obtained by expansion of the QA safety related list to include any additional non-safety related equipment.

By letter dated August 13, 1985, the NRC forwarded to NNECO the Systematic Assessment of Licensee Performance (SALP) for Millstone Unit No. 1 for the period from September 1, 1983 to February 28, 1985. Three rating areas (plant operations, maintenance, and surveillance) are directly applicable to this topic. In the area of plant operations, which includes engineering support, design control, training, staffing, and overall conduct of facility operations the staff found that a strong sense of precaution was evident during several planned power reductions for corrective maintenance. QA audits are done by corporate staff and are generally broad in scope. The audit staff is small and aggressive with good communications to senior management. Analysis of LERs indicated a high level of performance.

In the area of maintenance, the equipment classification program was reviewed to determine proper equipment classification commensurate with system application. The program was judged to be effective. The current manual program is planned to be replaced by an automated system. QA involvement in post-maintenance testing and in modifications was reviewed and found to be aggressive, well supported by management and generally thorough.

In the area of surveillance, a master surveillance control list correlates surveillance to licensee requirements and receives management oversight. Individual departmental controls are effectively used to schedule and track completion of surveillance.

The rating for each of these three areas was 1, the highest SALP rating category. This rating together with the fact that, as of August 13, 1985, Millstone Unit No. 1 was on-line for 374 continuous days, are indicative of good QA maintenance and surveillance programs with management support and involvement for both safety related and non-safety related equipment.

The staff however recommends that NNECO cross check their QA list against the equipment in the PSA to determine if all of the equipment defined in the PSA to be important to safety is included in the QA list.

NNECO did not estimate an ARM priority score for this topic. The staff recommendation for a cross check of the QA list is rated by the staff as a low implementation priority.

3.3.39 Topic 1.39, Radiation Protection Plans

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.39 (TMI Action Plan Item III-D.3.1).

NUREG-0660, the TMI Action Plan, proposed a project to improve nuclear power plant worker radiation protection programs by better defining the criteria and responsibility for such programs. Detailed appraisals of health physics programs at all operating facilities were performed and found that certain generic deficiencies existed at many plants due in part to lack of specific performance criteria and/or assigned responsibility. The establishment of a radiation protection plan as a guidance document for implementing procedures has been proposed.

By letter dated October 22, 1985, NNECO stated that the radiation protection plan at Millstone Unit No. 1 compares well with the draft guidance document and that, although some differences do exist, all of the basic criteria are addressed.

During the licensing review of Millstone Unit No. 3, the Millstone Radiation Protection Plan, which is applicable to the three Millstone units, was reviewed by the staff. The staff concluded in its evaluation (NUREG-1031) that the radiation protection program will maintain in-plant radiation exposures within the applicable limits of 10 CFR 20 and will maintain exposures as low as reasonably achievable (ALARA) in accordance with Regulatory Guide 8.8.

By letter dated August 13, 1985, the NRC forwarded to NNECO the SALP for Millstone Unit No. 1 for the period from September 1, 1983 to February 28, 1985. One rating area, radiological controls, is directly applicable to this topic. The assessment found that the radiation protection program is defined by good policies and procedures. The licensee had good performance in the area of contamination control, personnel monitoring, radiological surveillance and job control, instrumentation

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reliability and effluent control. The licensee has also implemented a formal ALARA program designed to analyze specific tasks and effect dose reduction methods, as well as monitor task performance relative to performance goals. Overall, the licensee's performance during major projects involving high levels of radioactivity demonstrated planning and preparation, good procedure development and the establishment of acceptable radiological controls.

However, the staff found some deficiencies in the licensee's radiological controls. These deficiencies were not in the area of the radiation plan itself, but in the area of implementation of the plan. The SALP rating was a Category 2, which indicates that licensee management attention is evident and resources are adequate and reasonably effective so that satisfactory safety performance is being achieved. The SALP rating board recommended an evaluation of training for first level supervisors as a measure for improving adherence to requirements and to upgrade adherence to routine radiation protection requirements by individual workers.

In the staff's evaluation of issue III.D.3.1 in NUREG-0933, the staff agreed to support alternative regulatory concepts which recognize the contributions of industry self-policing programs to the extent that such programs are effective and consistent with NRC regulatory responsibilities. As a result, the staff entered into a "Coordination Plan for Radiological Protection Activities" with INPO under a "Memorandum of Agreement Between INPO and the USNRC." Under this agreement, over the two-year period outlined in the Coordination Plan, NRR staff developed a method for evaluating industry performance in radiation protection programs incorporating ALARA concepts at power reactors and observed the INPO evaluation and assistance process at a number of operating facilities.

The staff performed analyses of a number of radiological data trends as part of the effort to determine if the power reactor industry has achieved successful ALARA-integrated radiation protection programs. An analysis of these trends and portions of the supporting data bases were documented in the report, "Summary Analysis of Selected Radiological Trends at Power Reactors," dated May 19, 1986.

Following the staff' completion of data and evaluation of a number of trends in radiological protection at power reactors, the staff concluded in a letter dated May 19, 1986 that most power reactor radiation protection programs are adequately incorporating ALARA concepts and can satisfactorily perform at a level which meets the objectives of Item III.D.3.1. Thus, this issue was resolved and no new requirements were established.

On the basis of the radiation protection plan in effect, the staff's review of that, and the licensee's implementation of the plan and the staff's conclusions in NUREG-0933, the staff finds that NNECO satisfies the intent of Topic 1.39 and, as such, this issue is resolved. However, as indicated by the SALP finding, NNECO should strive to improve its implementation of the radiation protection plans.

3.3.40 Topic 1.40, Bolting Degradation or Failure

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.40 (Generic Issue 29).

There are numerous bolting applications in nuclear power plants. The most crucial bolting applications are those constituting an integral part of the primary pressure boundary. Failure of these bolts could result in the loss of reactor coolant and thus jeopardize safety operation. Other bolting applications, such as component support or embedded anchor bolts, are essential for withstanding transient loads created during abnormal or accident conditions. In recent years, the number of bolting related incidents has increased. Therefore, there is concern regarding the integrity of the primary pressure boundary and the reliability of the component support structures.

NUREG-0933 recognized that there was no simple solution to this issue but stated that improvements in one or all of the five following areas could be recommended: design, materials, fabrication, installation and inservice inspection. In evaluating the relative priority of this issue in NUREG-0933, the staff only considered improvements in inservice inspection.

In September 1984, INPO SOER 84-5, "Bolt Degradation or Failure in Nuclear Power Plants," was issued and it provided recommendations to address the concerns of this issue. By letter dated October 16, 1985, NNECO addressed the recommendations of the INPO SOER. The staff recognizes that the NNECO program for bolting inspection addresses the INPO SOER recommendations and NRC requirements. By letter dated December 23, 1985, NNECO informed the staff of the discovery of fully severed bolting on main steam line support base plates. On January 2, 1986, the staff concluded that the corrective actions for this incident are adequate to support the safe operation of the plant. However, the staff requested additional information to identify the cause of the bolting failure.

The staff concluded that NNECO meets the intent of Topic 1.40 since the licensee observes industry codes and standards and NRC regulations in the design of, materials for, fabrication of, installation of and inspection of bolting. Therefore, the staff concluded that the licensees present bolting program is adequate and need not be addressed in the integrated assessment, except for the following two exceptions, as detailed in the staff's January 2, 1986 letter:

1) The licensee should address the concerns in the staff's January 2, 1986 letter, and
2) The licensee should evaluate the need for more frequent visual examinations of the plant bolting. (The failed bolting was found during a routine plant walkdown. Alerting plant personnel of the need to examine bolting conditions during system maintenance and related plant activities may satisfy this need).

In a letter dated July 31, 1986, NNECO stated that plant personnel have been alerted to the need for more frequent visual examinations of support plate bolting. Also, during the 1987 refueling outage, NNECO will visually inspect 100% of the Class 2 and Class 3 anchors. Unless circumstances warrant otherwise, NNECO will resume ASME Code Section XI inspections in subsequent outages.

The staff has reviewed information submitted by letter dated February 6, 1986, by NNECO in response to the staff's January 2, 1986, request and finds it acceptable. The staff also finds the commitment to perform a 100% inspection of the Class 2 and Class 3 anchors to be acceptable. However, the staff recommends that the need for more frequent visual examinations be reinforced by an addition to the relevant walkdown checklist. The staff rates the implementation priority for this checklist modification to be low.

3.3.41 Topic 1.41, Flooding of Compartments by Backflow

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.41 (Generic Issue 77).

On July 1, 1983, the NRC issued I&E Information Notice 83-44, "Potential Damage to Redundant Safety Equipment as a Result of Backflow through the Equipment and Floor Drain System," to address the concern that improperly designed drain systems could contribute to equipment damage as a result of backflow.

By letter dated October 16, 1985, NNECO submitted an evaluation of the equipment and floor drain system design for Millstone Unit No. 1. NNECO stated that the results of a review previously conducted for IE Circular 78-06, "Potential Common Mode Flooding of ECCS Equipment Rooms at BWR Facilities," showed that flooding in one ECCS equipment room would not result in flooding of the redundant equipment room since each ECCS room has a separate floor drain sump, with no cross connections.

NNECO also stated that the emergency diesel generator, standby gas treatment, feedwater coolant injection, isolation condenser and standby liquid control systems were not capable of being flooded because of the elevation of these components. Systems such as the gas turbine generator, emergency service water or service water systems are not affected by the equipment or floor drain system since they can drain directly to Long Island Sound.

Further, Departmental Instruction No. 1-OP-6.13, "Plugging of Floor Drains," states that a Plant Design Change Request is required for plugging of floor drains. This request is reviewed by the Plant Operations Review Committee.

A review of the Millstone Unit No. 1 plant drainage system design by NNECO concluded that there exists the possibility of backflow through drains which empty into catch basins and oil separator pits located outside the recombiner, turbine and gas turbine buildings. Drains in these buildings for which backflooding could be postulated were identified. Millstone Unit No. 1 Off-Normal Procedure 514A, "Natural Occurrences," has been revised to provide guidance to operators as to which plant drains are to be temporarily plugged in the event of site flooding.

Based on the design of the Millstone Unit No. 1 structures and systems, the staff concludes that the possibility of damage to equipment from flooding through equipment and floor drain systems is remote. The possibility exists for equipment flooding caused by backflow from natural site flooding. However, given the existence of a procedure to preclude the backflow and time to implement the procedure (possible maximum flood levels, necessary procedures and equipment to mitigate flood effects, and time to implement procedures were reviewed in SEP and found to be acceptable) the possibility of equipment flooding is remote.

However, it should be noted that NNECO is currently conducting an internal flooding study. Internal flooding could be cause for common mode failure. The staff believes that this study when complete will be a significant addition to the PSA and understanding of the Millstone Unit No. 1 plant. The staff rates the implementation priority of this study as medium. NNECO is currently scheduled to complete this study in 1987. This completion date is consistent with the staff's medium implementation priority.

3.3.42 Topic 1.42, MSL Leakage Control Systems

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety and generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.42 (Task Action Plan Item C-8).

General Design Criterion 54 of 10 CFR 50, Appendix C, requires, in part, that piping systems penetrating primary containment be provided with leak detection, isolation, and containment capability having redundancy, reliability and performance capabilities that reflect the importance of isolating these piping systems. Regulatory Guide 1.96, "Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants," was issued to describe an acceptable method of meeting the requirements of GDC 54.

The NRC conducted a survey in 1982 which indicated a high frequency of measured MSIV leakage at some plants, which may be significantly in excess of the Standard Technical Specification limit of 11.5 SCFH. The NRC proposed the need for improved MSIV maintenance, more frequent testing or installation of a MSIV leakage control system. Task Action Plan Item C-8 was initiated to investigate whether the leakage control system recommended in Regulatory Guide 1.96 was acceptable.

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By letter dated October 16, 1985, NNECO stated that Millstone Unit No. 1 does not employ a MSIV leakage control system. The plant technical specification 4.7.F.2.C limits MSIV leakage to 11.5 SCFH. A review of plant performance from 1970 to 1985 indicated that the MSIVs failed to meet the leakage limit several times, with the maximum leakage rate less than 40 SCFH. Other BWRs have experienced excess leakage rates on the order of thousands of SCFH.

NNECO concluded that since Millstone Unit No. 1 does not employ a MSIV leakage control system, concerns regarding adverse impact of the system operation on dose consequences are not applicable. Further, since leakage rates at Millstone Unit No. 1 have exceeded limits but are far below those experienced at other BWRs, NNECO concludes that existing maintenance practices are adequate to ensure valve operability and limit leakage (MSIV maintenance involves preventive refurbishment of the valve seat and poppet; surveillance is conducted monthly).

The staff has reviewed NNECO's submittal and concludes that the addition of a MSIV leakage control system at Millstone Unit No. 1 would not provide a substantial improvement in safety. The current surveillance and maintenance procedures together with the operating history of the plant and NNECO's participation in the BWR Owners Group investigating leakage control form the basis for the determination that NNECO satisfies the intent of this topic and, as such, this topic is considered resolved.

3.3.43 Topic 1.43, Water Hammer

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.43 (USI A-1).

NNECO informed the staff that the analytical efforts to include the effects of water hammer on the isolation condenser supply and return lines were complete. As a result of the analyses, several additional piping restraints were installed. On August 10, 1981, a reactor scram at Millstone Unit No. 1 resulted in a water hammer event in the isolation condenser. An engineering evaluation by NNECO demonstrated the structural adequacy of the isolation condenser to withstand the water hammer loading. On November 6, 1981, a staff safety evaluation was issued accepting NNECO's isolation condenser water hammer analyses, but recommended that penetration X-10A be reevaluated to assure a safety factor of at least four.

By letter dated August 30, 1982, the staff issued a safety evaluation that concurred with NNECO's short-term and long-term commitments to address possible future water hammer events. NNECO committed to: (1) implement a feedwater pump trip on high reactor level; (2) lower the RWCU system isolation setpoint to provide system availability for reactor vessel fill and address associated post-accident radiological concerns;

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(3) evaluate lowering the programmed reactor water level setpoint following reactor trip to avoid vessel overfill, and (4) implement low flow feedwater controller improvements to allow remote system actuation from the control room and maintain constant reactor vessel water level automatically.

By letter dated October 23, 1985, NNECO provided information on the status of USI A-1 for Millstone Unit No. 1. NNECO stated that Item (1) above has been implemented. Item (2) is being evaluated under ISAP Topic 2.20. NNECO stated in a telephone conference call, that Item (3) was evaluated and it was found that the response of the system was such that a cost-beneficial modification could not be developed to resolve this item. Item (4) was implemented in 1984. Also, the issue of water hammer events in the Control Rod System was resolved in ISAP Topic 1.22. Additionally, the reevaluation of containment penetration X-10A is being evaluated under ISAP Topic 1.48.

In a letter dated March 3, 1986, the staff stated that in order to adequately resolve this topic, NNECO should present the arguments for Item (3) in the integrated assessment. The other items in this topic are resolved. NNECO did not estimate the ARM implementation priority for Item (3). The staff finds that the implementation priority should be low.

Also, the staff recognized that it is not feasible to make all the design changes necessary to preclude water hammer events since many events are of plant specific origin and the modifications necessary to prevent the event are not evident until after a water hammer has occurred. The licensee should recognize that water hammer events are still possible.

3.3.44 Topic 1.44, Asymmetric Blowdown Loads on Reactor Systems

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.44 (USI A-2).

In the event of a postulated reactor coolant system piping rupture at the vessel nozzle, asymmetric LOCA loading could result from forces induced on the reactor vessel internals by transient differential pressures across the core barrel and by forces in the vessel due to transient differential pressures in the reactor cavity. This issue was designated as USI A-2 and was resolved upon issuance of NUREG-0609, "Asymmetric Blowdown Loads on PWR Primary Systems," in January 1981. PWRs were evaluated by the staff for the effects of asymmetric blowdown levels and were found, on a generic basis, based on fracture mechanics analysis, to be adequately designed for this event. BWRs were generically evaluated under the GESSAR review using the same analysis methods as PWRs.

By letter dated July 7, 1982, the NRC requested NNECO to provide the status of the USIs at Millstone Unit No. 1. Although USI A-2 was not directly applicable to BWRs, the NRC requested all licensees to confirm the applicability of the staff positions on A-2 to their facilities. By letters dated October 13, 1982 and October 23, 1985, NNECO reported on the status of USI A-2. NNECO stated that although similar types of loads associated with a rupture of piping in primary systems in BWRs are expected to occur, the overall safety significance is considered to be much less because of the lower operating pressures in primary systems of BWRs.

Based on this information, the staff considers this topic to be resolved pending any future requirements resulting from the generic BWR asymmetric blowdown load review.

3.3.45 Topic 1.45, Systems Interactions

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.45 (USI A-17).

USI A-17, "Systems Interactions in Nuclear Power Plants," addresses the development of a systematic process to review plant systems to determine their impact on other plant systems. The purpose of the task is to identify where present design, analysis and review procedures may not acceptably account for potentially adverse systems interactions and to recommend the regulatory action that should be taken to rectify deficiencies. The scope of this issue was redefined to limit it to functionally coupled, spatially coupled and induced human coupled interactions which could degrade a safety function.

Millstone Unit No. 1 was a participant in the Systematic Evaluation Program (SEP). Although SEP was not designed to explicity address the concerns of USI A-17, the review criteria for some SEP topics included evaluations of hazards created by intersystem deficiencies. Also, interactions of spatially coupled components (i.e., pipe break effects and seismic considerations) and operating experience were reviewed. The corrective actions taken as a result of the SEP review will help to preclude adverse systems interactions.

Also, Millstone Unit No. 1 participated in IREP and NNECO has completed a PRA for this plant. The risk/safety based analyses also served to evaluate some of the possible systems interactions scenarios. NNECO is already conducting an internal flooding study and is planning to conduct an external hazards study.

Generic Letter 82-33 (requirements from Supplement 1 to NUREG-0737), dated December 17, 1983, detailed requirements for emergency response capability, including a safety parameter display system (ISAP Topic 1.08) and post-accident monitoring capabilities (ISAP Topics 1.09 and 1.10).

These requirements will enhance the ability of the operator to perform mitigating actions in response to events including those due to adverse systems interactions.

The presently proposed staff resolution for this issue will require no plant modifications. The staff concludes that, through participation in SEP and IREP, the performance of a PSA and its routine updating, and other risk analyses, such as internal flooding and external hazards, the issue of systems interactions has been adequately addressed for Millstone Unit No. 1 and therefore, this topic is resolved.

3.3.46 Topic 1.46, Determination of SRV Dynamic Loads

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.46 (USI A-39).

Operation of BWR primary system pressure relief valves can result in hydrodynamic loads on the suppression pool retaining structures or those structures located within the pool. This dynamic loading issue was addressed in USI A-39 and was resolved with the issuance of NUREG-0793, "Guidelines for Confirmatory Inplant Tests of Safety Relief Valve Discharges for BWR Plants," for BWR Mark I containments in 1981.

By letters dated October 13, 1982 and October 16, 1985, NNECO presented the status of USI A-39 for Millstone Unit No. 1. NNECO stated that it had submitted a report on pool dynamic loads for Millstone Unit No. 1, which provided a description of the application of the generic Mark I pool dynamic loads and methods, as well as an evaluation of the containment and components to accommodate pool dynamic loads. This report was reviewed and the staff issued a safety evaluation on September 12, 1984, that concluded that the licensees analysis and modifications are sufficient to satisfy the original design safety margins for the lifetime of Millstone Unit No. 1. On this basis, the staff concludes that Topic 1.46 is resolved.

3.3.47 Topic 1.47, Containment Emergency Sump Performance

During the development of the ISAP program for Millstone Unit No. 1, the staff identified a number of safety/generic issues, derived from the high-priority issues in NUREG-0933, that the staff felt could be substantially addressed on a plant specific basis in concert with the PSA. One of these issues is Topic 1.47 (USI A-43).

USI A-43 safety concerns deal with post-LOCA conditions that can degrade long-term recirculation capability. These safety concerns deal with the potential loss of pump net positive suction head (NPSH) margin due to air ingestion to the pump or suction strainer blockage resulting from LOCA generated debris.

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Full scale experiments on BWR type suction strainers have demonstrated that for typical submergences and flow rates, the strainers act as effective vortex suppressors such that air ingestion is very small. Thus, the likelihood of loss of NPSH margin due to air ingestion is low.

In Millstone Unit No. 1, the insulation is of reflective metallic and blanket types. The blowdown and transport of insulation debris to the torus will be impeded by the physical layout of Millstone Unit No. 1. For metallic insulation that is transported to the torus, the low bulk fluid flow and the elevation of the intakes relative to the torus bottom makes the probability that this debris will be drawn to the strainers low. Blanket type insulation could be drawn to the strainers and over a period of time lower the RHR flow rate. It is possible, because the flow rate is monitored and because flow rates can be reduced substantially later in the accident sequence, that operator actions could mitigate the effects of any blockage.

In a letter dated March 3, 1986, the staff stated its opinion that Millstone Unit No. 1 meets the intent of the safety concerns in Topic 1.47 with the exception of the possibility of blanket type insulation causing reduced flow and possible procedural improvements. The staff ranks the implementation priority of any future actions on this topic to be low.

3.3.48 Topic 1.48, Safety Factor for Penetration X-10A

As part of the review of the Millstone Unit No. 1 isolation condenser for water hammer loads (refer to ISAP Topic 1.43), the staff found that the design of the isolation condenser was acceptable except that NNECO should demonstrate that the factor of safety for containment penetration X-10A is at least four.

By letter dated October 23, 1985, NNECO stated that the required analysis is currently in progress.

The results of the staff's SEP review of the Millstone Unit No. 1 piping indicated that the piping will adequately resist seismic loads. Millstone Unit No. 1 complies with the requirements in IEB 79-02 and 79-14. The SEP review of pipe break at Millstone Unit No. 1 indicated that the piping met at least a factor of safety of 2 for pipe break with one time loading. Also, it is noted that the support for penetration X10A is an advancement over the original support strength. Therefore, the staff concludes that the implementation priority for NNECO to complete its penetration support analysis is low.

3.3.49 Topic 1.49, Reactor Vessel Surveillance Program

Subsequent to the issuance of the staff's screening review letter dated July 31, 1985, it was determined that the scope of Topic 1.49 did not meet the criteria for inclusion in the Millstone Unit No. 1 ISAP. Specifically, the staff concludes that Topic 1.49 deals with a routine licensing matter and should, therefore, be evaluated outside of ISAP. Recognition of the amount of resources needed to complete this issue and all other routine licensing issues in a timely manner should be factored into the development of the integrated schedule by NNECO.

Therefore, Topic 1.49 will no longer be considered in the ISAP. However, NNECo should consider modifications to the present reactor vessel surveillance program if they plan to change periods between refueling or request a plant lifetime extension.

3.3.50 Topic 1.50, Isolation Condenser Startup/Makeup Failures

In the Millstone Unit No. 1 PSA it was determined that isolation condenser makeup failures and initiation/startup failures appear in 11 of the 18 dominant sequences. The PSA further indicates that the makeup failures are dominated by a MOV which fails to open and by failure of the two diverse fire water supply pumps. The initiation/restoration failures are dominated by contact pair failure and failure of motor operated valve 1-IC-3 to open. In a letter dated March 3, 1986, the staff identified this issue as warranting evaluation in the integrated assessment. The staff stated that the licensee should evaluate, by specific probabilistic analyses or by mechanistic analyses, potential improvements to the isolation condenser to improve its availability/reliability.

In a letter dated July 31, 1986, NNECO stated that they will provide the information requested at a later date. Also, NNECO did not estimate in ARM implementation priority for this topic.

Since this topic was derived from the staff's review of the PSA events with safety significance whose resolution will make quantifiable improvements in the CMF, the staff rates this topic as a medium implementation priority.

3.3.51 Topic 1.51, Failure to Restore Main Condenser

The main condenser at Millstone Unit No. 1 is an important part of transient and accident mitigation because the unit has 100% turbine bypass capacity and the main condenser is the sink for primary heat loads.

The Millstone Unit No. 1 PSA determined that failure to restore the main condenser contributes to sequences estimated to have a core melt frequency of about 1E-4 per year. In a letter dated March 3, 1986, the staff identified this issue as warranting evaluation in the integrated assessment. The staff stated that the licensee should evaluate methods whereby the capability to restore the main condenser could be improved.

In a letter dated July 31, 1986, NNECO stated that they will provide the information requested at a later date. Also, NNECO did not estimate in ARM implementation priority for this topic.

Since this topic was derived from the staff's review of the PSA events with safety significance whose resolution will make quantifiable improvements in the CMF, the staff rates this topic as a medium implementation priority.

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3.3.52 Topic 1.52, Safety/Relief Valve Failure-Setpoint Drift

The Millstone Unit No. 1 PSA identified that failure of the safety/relief valves to close contributes to sequences estimated to have a core melt frequency of about 1E-4 per year. In addition, the Millstone Unit No. 1 operating experience review identified a general problem of BWR safety/relief valve setpoint drift. In a letter dated March 3, 1986, the staff identified this issue as warranting evaluation in the integrated assessment. The staff stated that the licensee should evaluate methods whereby the safety/relief valves reliability can be improved.

Although the PSA identified safety relief valve failure as being a contributor to 11 of the 18 dominant sequences, the frequency of failure to close for safety/relief valves probably was driven by the failure of the older design three-stage valves. The two-stage valves currently installed at Millstone Unit 1 have had a better record of closure. However, the three-stage valves have tended to stick closed and open at too high a pressure rather than sticking open like the two-stage valves. There is a concern that when the valves open at a higher pressure that the transient may appear different to the operator due to the pressure characteristics or that the primary system may overpressurize. To date, when stuck, these valves have opened on a manual open signal.

In a letter dated July 31, 1986, NNECO stated that they will provide the information requested at a later date. Also, NNECO did not estimate in ARM implementation priority for this topic.

Since this topic was derived from the staff's review of the PSA events with safety significance whose resolution will make quantifiable improvements in the CMF, the staff rates this topic as a medium implementation priority.

3.3.53 Topic 2.01, LPCI Remotely Operated Valves 1-LP-50A and B

Millstone Unit No. 1 Technical Specification Section 4.7.A.1 requires that the suppression chamber water level be checked once every shift to assure that the water level in the torus is within acceptable limits. If the water level exceeds the maximum allowable level, water is drained to the radwaste system by opening two normally closed 3-inch manual gate valves (1-LP-50A and B). During certain accident conditions, these valves will become inaccessible.

By letter dated August 13, 1985, NNECO proposed to provide the capability of remote operation for these valves. A feasibility study was proposed to determine the best option for providing this capability. In a letter dated March 3, 1986, the staff concurred in the scope for this topic.

In a letter dated August 23, 1985, NNECO provided the PSA summary for this topic. The PSA summary investigated the impact on risk of providing a remote operation capability for these valves to ensure the capability of draining torus water even if high radiation levels are present. The public safety attribute score was calculated using evaluation Method B. It was envisioned by NNECO that the remote operation of these valves would allow the operator to perform a feed and bleed operation on the torus. However, success of feed and bleed required a torus drain rate of about 1000 gpm while the actual drain rate of the 3-inch torus drain line and the capacity of the liquid radwaste system are too small to be of benefit. In addition, remote operation of these valves may slightly increase the probability of inadvertently opening the valves during an accident and thereby divert LPCI pump flow to the radwaste system. However, this small divertment will not impact the success criteria for the LPCI system. NNECO estimated a public safety attribute score for this topic of 0.1 on a scale of -10 to +10.

The staff review of the PSA summary for this topic concluded that the impact of this proposed modification, both positive and negative, is insignificant.

Also, it has been demonstrated that the addition of remote operation capability for these valves and their associated downstream piping is too small to be considered for a potential torus bleed-and-feed long-term decay heat removal scheme.

The staff's review of the deterministic and probabilistic evaluations for this topic found that providing remote operators for valves 1-LP-50A and B would provide little if any benefit. While the estimated cost to implement this project is relatively small, its cost outweighs the benefits. The staff recommends that this topic have a low priority.

3.3.54 Topic 2.02, Drywell Humidity Instrumentation

Presently, neither of the two methods for primary coolant leak detection employed at Millstone Unit No. 1 provides for continuous leak detection monitoring. Accordingly, there exists a possibility that pipe cracks might propagate to a greater degree before detection than would be the case if the leak detection system operated continuously.

By letter dated September 26, 1985, NNECO proposed to perform an engineering evaluation to determine the best method for continuous monitoring of the humidity, and airborne gaseous and particulate contamination in the drywell. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In NNECO's July 31, 1986, submittal, NNECO estimated that since existing leakage detection schemes employed at Millstone Unit No. 1 would be able to adequately detect small LOCAs (large LOCAs would be evident to operators very quickly by means of instrumentation other than standard leak detection instrumentation) in about 4 hours. The addition of continuous drywell humidity instrumentation will provide only a small increase in public safety.

A related topic 2.25, Drywell Temperature Monitoring System Upgrade, together with the instrumentation in this topic would add to the overall leakage detection system capabilities. However, these systems are only

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indirect means of detecting pipe breaks. Therefore, because of the marginal improvement to the capability of the Millstone Unit No. 1 leakage detection system, the staff recommends that the implementation priority of these two topics be low.

3.3.55 Topic 2.03, Process Computer Replacement

The process computer at Millstone Unit No. 1 is presently nearing the end of its expected useful life. The process computer is necessary during plant startup and for monitoring and performing NSSS calculations during power ramp-up and ramp-down conditions. During normal operations, the process computer is used for daily fuel surveillance. The failure of the process computer during normal operation does not affect power generation and is not limited by technical specification.

As part of the TMI Action plan, all licensees and applicants for operating licenses were required to install a Safety Parameter Display System (ISAP Topic 1.08). By letter dated September 6, 1985, NNECO stated that it was replacing its process computer. The new process computer will have a larger storage capacity and be capable of meeting the interaction requirements of the SPDS. The process computer replacement is currently ongoing. In a letter dated March 3, 1986, the staff concurred on the scope of this topic.

During the 1985 refueling outage NNECO installed and tested a 600 amp DC breaker that will be the supply breaker for the process computer uninterruptible power supply.

The staff recognizes that the installation of the plant process computer is currently being implemented. The staff recommends that installation be completed on its current schedule because of its importance to related topics, such as Topic 1.08, Safety Parameter Display System.

3.3.56 Topic 2.04, High Steam Flow Setpoint Increase

The current high steam flow setpoint for automatic isolation is 120 percent of rated flow. In order to perform turbine stop valve testing, reactor power must be reduced to approximately 90 percent for the duration of the test (several hours) in order not to reach the high steam flow setpoint and generate an MSIV isolation signal and a reactor trip.

By letter dated August 13, 1985, NNECO proposed to evaluate the feasibility of an increase in the flow setpoint to 140 percent of rated flow. This increase will allow testing of the turbine stop valves at 100 percent power without reaching the trip setpoint. As presently defined, the increase in setpoint can be accomplished by a calibration change in existing hardware. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated August 15, 1985, NNECO provided the PSA summary for this topic. The PSA summary investigated the impact of increasing the setpoint for MSIV closure from 120% to 140% of rated steam flow and the elimination

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of the weekly power reduction for turbine stop valve testing. NNECO stated that the only adverse impact of increasing the setpoint is for those steam line breaks which result in a flow rate between 120% and 140% in the main steam lines. If the proposed change is implemented, these specific breaks instead of isolating automatically will require the operator to manually close the MSIVs. NNECO estimated the increase in core melt frequency for this modification to be about 1.4 E-7 per year. This would result in a public safety attribute score of -0.05.

The staff anslysis of the PSA summary for this topic found two areas where the treatment of the analysis of this issue was questionable (refer to Section 4.15.3 of Appendix C). The staff found the increase in public risk to be about 15 times higher than the PSA summary result. The staff estimates the public safety attribute score to be about -0.6.

Based upon the staff's review of the PSA summary and attribute scores for this issue, the staff finds that the only positive impact this issue would have is on economic performance of the plant. While this is indeed an incentive for making some plant modifications, the staff finds that the decrease in public safety is not outweighed by the increase in economic performance. The staff position is that the implementation priority for this issue should be low.

3.3.57 Topic 2.05, Hydrogen Water Chemistry Study

BWR nuclear power plants have exhibited cracking in austentic stainless steel due to intergranular stress corrosion cracking (IGSCC), a phenomenon which can be attributed to susceptible, stressed materials exposed to a corrodent.

By letter dated August 13, 1985, NNECO proposed to study the feasibility of altering the primary water chemistry at Millstone Unit No. 1 by injecting hydrogen into the feedwater. The hydrogen injection would suppress oxygen formation (an IGSCC corrodent) in the primary coolant. However, the hydrogen will also increase the volatility of nitrogen and thereby, increase the concentration of N-16 in the steam, causing a possible increase in personnel exposure. Also, the hydrogen will change the chemical character of the reactor coolant from oxidyzing to reducing leading to the possibility of different corrosion problems. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO stated that due to the increased volatility of nitrogen in the reactor coolant when hydrogen is injected, the high-high radiation trip setpoints in the main steam would have to be adjusted whenever hydrogen is injected. Also, the injection will result in more personnel exposure during routine plant activities. However, this system would inhibit IGSCC if the study goals were met, thereby reducing the probability of a LOCA.

During the 1985 refueling outage a back-up isolation valve on the cleanup system return line to the main condenser was added to allow the installation of the hydrogen piping without a plant shutdown.

The staff would rate this study to be medium in the implementation priority rankings. The staff also encourages NNECO to investigate the problems encountered by other utilities in implementing a hydrogen injection system.

3.3.58 Topic 2.06, Condenser Retube

The main condenser at Millstone Unit No.1 has tubing made of a 70/30 copper-nickel alloy that is susceptible to erosion and corrosion problems caused by sea water. By letter dated August 13, 1985, NNECO proposed to evaluate the replacement of the copper-nickel tubing with titanium tubing. Titanium tubing is not susceptible to the erosion/corrosion mechanisms. However, it is substantially more expensive and has a lower heat transfer coefficient requiring approximately 10% more tubing to achieve equal condensing capability. The scope of this topic for the ISAP integrated assessment is the development of a priority for completing the condenser retube. In a letter dated March 3, 1986, the staff concurred in the scope for this topic.

In a letter dated August 7, 1985, NNECO provided the PSA summary for this topic. The PSA summary investigated the impact of the complete replacement of the existing condenser tubing with titanium tubing. Retubing will help to preclude the situation in which feedwater and the main condenser must be isolated due to seawater intrusion. The PSA has shown that the loss of the main condenser sequence totals 64% of the predicted core melt frequency. The condenser retubing was estimated to prevent a .75% increase in the core melt frequency if the condenser was not modified. The public safety attribute score for this topic was calculated to be 1.25.

The staff review of the PSA summary concluded that the NNECO analysis was a bounding calculation on the impact of retubing the main condenser. The staff estimated that the minimum impact of this topic would be a public safety attribute score of about 0.55.

The benefits of retubing of the condenser are:

(a) Increase plant efficiency through an increase in heat transfer capability from the primary side to the secondary side (lower heat transfer coefficient but greater heat transfer area).

(b) Decrease radwaste control costs through a reduction in tube leakage.

(c) Decrease plant personnel exposures while performing maintenance on the condenser or testing for leaking tubes.

(d) Reduce the times the plant has to reduce power to condenser maintenance.

(e) Result in a slight decrease in core melt frequency and public risk.

However, titanium tubing is substantially more expensive than the current tubing and has a lower heat transfer coefficient. The proposed replacement of the condenser tubing would result in a economic performance attribute score of 3.5, personnel safety score of 3.5 and a personnel productivity score of 5.0. The staff has reviewed the overall score for this topic and find that this topic should rank medium in implementation priority.

3.3.59 Topic 2.07, Sodium Hypochlorite System

In order to prevent marine biofouling in cooling water systems using sea water as the cooling medium, chlorine is injected into cooling water systems at Millstone Unit No. 1. Liquid chlorine is stored on-site in 55-ton rail tank cars. The possibility exists that if a catastrophic failure of a tank car occurred, a toxic concentration of chlorine gas would be released both on-site and off-site.

By letter dated August 13, 1985, NNECO proposed to replace the gaseous chlorination system by an on-site bulk storage and distribution system of sodium hypochlorite which represents a smaller safety hazard. In a letter dated March 3, 1986, the staff concurred in the scope for this topic.

In a letter dated August 7, 1985, NNECO provided the PSA summary for this topic. The PSA summary investigated the impact of the elimination of liquid chlorine onsite and the installation of a solid sodium hypochlorite system. The analysis was performed using evaluation Method C. The public safety attribute score calculated by NNECO was 10 on a scale of -10 to +10.

The staff review of the PSA summary for this topic concluded that while the methodology chosen for the analysis is acceptable, the utility's estimate of the amount of the immediate release, the effects of the intermediate release and the failure rate of the tank car pressure relief valve are too high (refer to Section 4.17.3 of Appendix C for more details). Also, it did not appear that the PSA summary considered possible evacuation of the offsite population. The staff estimate of the public safety attribute scope for this issue was 1.75 on a scale of -10 to +10.

NNECO stated that their evaluation of this topic concluded that this modification will result in a large decrease in risk in both plant personnel and the general public living around the plant site by:

(a) Eliminating the risk of chlorine-leak accident which could injure or disable plant personnel and prevent the plant from being operated in a safe manner, and

(b) Eliminating the risk of direct exposure of the public to poisonous gas during a chlorine leak accident.

NNECO has made the decision, based on their PSA evaluation and corporate safety goals, to remove the chlorine tank cars from the Millstone site. NNECO has installed the sodium hypochlorite system. Therefore, this topic is resolved.

3.3.60 Topic 2.08, Extraction Steam Piping

As a result of a generic problem of steam piping erosion at other plants, NNECO has performed inspections of the extraction steam piping and found that the eighth, ninth and eleventh stages of extraction steam piping from the low pressure turbine and the high pressure heaters extraction steam piping need to be replaced.

By letter dated August 13, 1985, NNECO stated that the replacement of piping has already been initiated. The scope of this topic for the ISAP integrated assessment is the development of a priority for completing the piping replacement. In a letter dated March 3, 1986, the staff concurred in the scope for this topic.

In a letter dated August 15, 1985, NNECO provided the PSA summary for this topic. The PSA summary investigated the impact of replacing affected extraction steam piping on the prevention of piping failure. The PSA summary found that implementation of this project would reduce the likelihood of a future steam pipe rupture outside containment and reduce the likelihood of a future MSIV closure event. The PSA concluded that the implementation of this project would eliminate a 2.7% increase in core melt frequency. The public safety attribute score for this topic was calculated to be 1.75 a scale of -10 to +10. Also, this topic will greatly affect economic performance and personnel safety.

The staff review of the PSA summary concluded that NNECO analysis and results are reasonable and agrees with the medium priority ranking for this topic.

3.3.61 Topic 2.09, Upgrading of P&IDs

By letter dated August 26, 1985, NNECO informed the staff of a plan to upgrade the Millstone Unit No. 1 Piping and Instrumentation Diagrams (P&IDs) because of a developing problem of overcrowding, inconsistencies and illegibility of the existing P&IDs. As stated in the licensee's letter, implemenation of this topic has already begun. In a letter dated March 3, 1986, the staff concurred on the scope for this topic and stated that the resources necessary to complete this project should be factored into the integrated schedule.

In a related topic, Topic 1.15, it was proposed by NNECO to prioritize the implemenation of the Millstone Unit No. 1 FSAR update. As stated in the SER section for Topic 1.15, an exemption until March 31, 1987 was granted by the staff for completion of the FSAR update. As part of that exemption, the licensee was to submit certain component parts of the FSAR on a schedule established in the exemption. The updating of system descriptions and piping and instrumentation diagrams were considered component parts and were required to be submitted by July 1, 1986. Also, in ISAP Topic 2.29, NNECO proposed to update the FWCI design wiring drawings.

The staff has reviewed the ARM scoring for this topic and agree with its low priority ranking.

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3.3.62 Topic 2.10, Drywell Ventilation System

The original design of the drywell cooling system required 4 of the 5 coolers to be in continuous operation. Actual drywell heat loads required all 5 coolers to operate. For this and other reasons, an additional three coolers were installed, however testing of the coolers identified that a majority of the coolers were operating below their design capacity. The resultant elevated drywell temperatures could result in premature equipment degradation.

By letter dated August 13, 1985, NNECO proposed to perform an engineering evaluation to establish the most cost-effective method for reducing the drywell bulk air temperature. An initial phase of the evaluation has been completed and plant changes recommended. In a letter dated March 3, 1986 the staff concurred on the scope for this topic.

During the 1985 refueling outage NNECO installed five new cooling coils and has scheduled the remaining three for the 1987 outage.

In a letter dated July 31, 1986, NNECO estimated the public safety attribute score to be 0.05 based upon the length of time needed for drywell temperature to exceed environmental qualification temperature for electrical equipment if the coolers are lost. Also, loss of the drywell coolers will have negligible impact on core melt frequency. The staff has reviewed the ARM score for this topic and finds its medium ranking to be appropriate for supporting the proposed replacement schedule.

3.3.63 Topic 2.11, Stud Tensioners

Following development of an automated stud tensioner system, NNECO performed a cost-benefit analysis of the new system and found it beneficial because of decreased outage time for any outage requiring reactor vessel head removal.

By letter dated August 13, 1985, NNECO proposed replacement of the existing stud tensioners with the new automated system, modifying associated equipment, revising procedures and drawings and providing personnel training. The scope of the ISAP topic is the development of a priority for completing the replacement project. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO estimated the ARM score for this topic and found it to be high relative to most other topics. This score (shown in Table 4.1) is based upon decreased exposure to personnel because of the automation of stud tensioning, the decrease in plant downtime and increase in personnel productivity. However, this topic has no effect on public safety. The relatively low cost of implementation of this topic result in a relatively high valve/cost ratio.

The staff agrees with the low priority of this topic; however, when making the integrated schedule for this topic, the staff feels that other topics with similar ARM scores (see Table 4.1) but higher public safety attributes should be scheduled ahead of this topic.

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3.3.64 Topic 2.12, Reactor Vessel Head Stand Relocation

In 1975, the reactor building crane was modified to provide redundant lift capability. This modification limited the travel of the crane with respect to the reactor building floor resulting in the inability to line up the centerline of the reactor vessel head stand with the centerline of the crane, causing difficulty in placing the reactor vessel head on its stand.

By letter dated August 13, 1985, NNECO proposed evaluating the feasibility of relocating the centerline of the reactor vessel head stand. NNECO stated that any modifications will address the provisions of NUREG-0612, "Control of Heavy Loads." In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO estimated the ARM score (see Table 4.1) for this topic and found it to be high relative to most other topics. This score is based primarily upon the the increase in personnel safety and low cost of implementation. However, implementation of this topic has no effect on public safety.

The staff does not agree with the relative priority of this topic and feels that it should have a medium priority based upon its high value/cost ratio and low public safety attribute.

3.3.65 Topic 2.13, Turbine Water Induction Modifications

By letter dated October 9, 1985, NNECO informed the staff that Topic 2.13, a licensee initiated plant improvement, has been cancelled. Therefore, since the licensee no longer has any plans with respect to this topic, Topic 2.13 will no longer be considered in the ISAP.

3.3.66 Topic 2.14, Evaluation and Implementation of NUREG-0577

NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing in PWR Steam Generators and Reactor Coolant Pump Supports", was issued for comment in November 1979. In that report, the action plan was expanded to include BWR component supports. In October 1983, NUREG-0577 Revision 1 was published. In that report version, the scope of the action plan was no longer applicable to BWR component supports and the recommendations of the report were only applicable to pressurized water reactors in-the construction permit or preliminary design application phase of licensing. These conclusions were based on a value-impact analysis that demonstrated that modifications to existing support structures could not be justified. Also, the staff could find no evidence of low fracture toughness or lamellar tearing in BWRs. Therefore, operating BWRs like Millstone Unit No.1 are not subject to the requirements of NUREG-0577.

However, at the time of the start of ISAP for Millstone Unit No. 1, this project was still active in the licensee's project tracking and was therefore included in the proposed scope for ISAP. Therefore, based upon the scope of NUREG-0577 Revision 1, ISAP Topic 2.14 is considered to be resolved.

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3.3.67 Topic 2.15, Torque Switch Evaluation for MOVs

I&E Information Notice 84-10, "Motor-Operated Valve Torque Switches Set Below the Manufacturers Recommended Value," was issued to inform licensees of recent experience where a licensee determined that a number of torque switches were improperly set.

By letter dated October 2, 1985, NNECO proposed to initiate an investigation to determine if all safety-related MOV torque switch setpoints are within the manufacturer's recommended setpoint range and develop an inspection procedure for use in monitoring MOV torque switch setpoints during refueling outages. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO stated that the scope of this topic has been enlarged to include their response to I&E Bulletin 85-03 on common mode failures. This program will achieve the following:

(1) Proper switch settings for each safety-related motor-operated valve will be defined;

(2) As a result of (1) above, individual switch settings on each MOV shall be changed as appropriate and each valve will be demonstrated operable; and

(3) Inspection procedures will be prepared or revised to ensure that correct switch settings are determined and maintained throughout the life of the plant.

NNECO did not estimate the ARM score for this topic; however, the staff finds that because of the safety significance of many of the motor-operated valves this topic should be ranked medium. The November 1987 completion schedule committed to in response to I&E Bulletin 85-03 is appropriate for a medium priority. NNECO will factor this commitment into the integrated schedule for Millstone Unit No. 1.

3.3.68 Topic 2.16, Reactor Protection Trip System

Historically, the Reactor Protection System (RPS) has demonstrated setpoint drift problems which have led to difficulties in maintaining setpoint calibration and accuracy. By letter dated September 26, 1985, NNECO proposed a project which would: (1) investigate the possible replacement of the 120 second ADS timer with a state-of-the-art timer circuit to alleviate setpoint drift, and (2) remove two pressure switches from the ECCS pump start logic to allow ECCS pump start on either high drywell pressure or low-low water level, and automatic ADS actuation. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO stated that the 120-second ADS timer would provide a delay in automatic opening of the four safety relief valves upon a high drywell pressure and low-low water level signal. The time delay is intended to allow FWCI to restore reactor vessel water level in the event

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of a small LOCA. NNECO's probabilistic assessment of the issue involved determining whether the current ADS timer's accuracy of ±10% impacts public safety. NNECO determined that if the setpoint drifts in the positive direction, the reactor temperature would increase, but not to the point of core melt before ECCS injection occurs. If the set point drifts in the negative direction, ECCS injection would start earlier, lessening the severity of the accident. There would also still be enough time for FWCI to restore reactor vessel water level, if possible. Thus, replacement of the present 120-second ADS time with a more accurate state-of-the-art timer circuit, however, would deterministically reduce the risk of operation of the ADS outside of operating setpoint guidelines.

Removal of the two low reactor pressure permisive switches would alleviate potential safety impact problems due to their ±20 psig drift. NNECO calculated, however, that the modifications would result in no significant change in core melt frequency. These switches allow ECCS pump start on either high drywell pressure or low-low water level. An upwards drift allows the ECCS pumps to start sooner. A maximum downward drift delays ECCS cooling, but does not result in an increase in drywell temperature large enough to cause a core melt. NNECO additionally concluded that removal of these switches would make manual depressurization of the reactor (per the EOPs) easier in that the ECCS pumps would already be running when the EOPs direct the operator to manually depressurize the RCS.

NNECO's ARM value/cost ratio for this topic was estimated to be 0.0. The staff has reviewed the proposed project, the ARM attribute estimates and the the 120 second ADS timer. Based on the margin in the setpoint (time after loss of offsite power to need for FWCI) the staff concludes that this topic should have a low implementation priority.

3.3.69 Topic 2.17, 4.16kV, 480V and 125VDC Plant Distribution Protection

As part of NNECO's Appendix R re-review completed in early 1985, the Breaker Coordination Study was updated to ensure that the power supplies for components required for safe shutdown in the event of a fire would be available despite the failure of circuits not required for safe shutdown. The study was performed for both AC and DC distribution systems.

By letter dated October 1, 1985, NNECO proposed to perform a more extensive review (i.e., exceeding the scope of the Breaker Coordination Study) of the 4.16kV, 480V and 125VDC plant distribution systems. This review would include:

(1) verification of all protective relay and circuit breaker settings on the 4.16 kV and 480 V systems and recoordination, if required;
(2) establishment of criteria for setting selection for all protective devices, if recoordination is required:
(3) performance of a fault study to be used in the setting calculations;
(4) verification of the interrupting and momentary ratings for station service switchgear;

(5) documentation of protective relaying calculations and settings in accordance with procedures applicable to safety-related equipment;
(6) establishment of a document control system compatible with the requirements for nuclear plant records;
(7) verification of containment electrical penetration back-up protection coordination; and
(8) evaluation of the Appendix R review coordination study recommendations and conclusions.

In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO stated that this evaluation was currently ongoing and is scheduled to be completed during the 1987 refueling outage. The implementation date of any modification identified as a result of this evaluation would be in accordance with 10 CFR 50.48.

NNECO's ARM score for this topic was low due only to a very small public safety attribute score. However, the staff feels that the overall contribution of the plant power system to plant safety is high and as such this issue taken together with other plant power topics should be a medium implementation priority. The staff finds that the current evaluation schedule and implementation of modifications in accordance with 10 CFR 50.48 meets this medium priority.

3.3.70 Topic 2.18, Spent Fuel Pool Storage Racks/Transportation Cask

At Millstone Unit No. 1, if the spent fuel storage capacity is not increased, full-core off-load capability will not be possible in 1987 and reload discharge capability will not be possible by 1991. Loss of full-core reserve could reduce the options available for fuel storage and possibly impact maintenance operations during a shutdown. Loss of spent fuel discharge capability would prevent replacement of depleted fuel assemblies with new fuel, thereby terminating power generation capability at Millstone Unit No. 1 in 1991.

By letter dated October 9, 1985, NNECO proposed to evaluate the options available for increasing the spent fuel storage capacity at Millstone Unit No. 1. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO indicated that the ARM value/cost score for this topic would place it in a high implementation priority. This score was based solely on an economic performance attribute score of 10.0. The staff agrees with this attribute score; however, the staff feels that the public safety attribute score should be non-zero. This is based upon the licensee's responsibility to provide safe spent fuel storage during the expected lifetime of Millstone Unit No. 1. This expected lifetime is the length of the current full term operating licensee which will expire in May 2006. Therefore, the staff finds the relative ranking of this topic as high to be appropriate.

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3.3.71 Topic 2.19, DC System Review

By letter dated October 9, 1985, NNECO informed the staff that Topic 2.19, a licensee initiated plant improvement study, has been cancelled. Although, the staff was never informed of the scope of this DC system review, the staff does note that the DC system at Millstone Unit No. 1 is more reliable than the industry average and would rate a general DC system review as low. However, since the licensee no longer has any plans with respect to this topic, Topic 2.19 will no longer be considered in ISAP.

3.3.72 Topic 2.20, RWCU System Isolation Setpoint Reduction

The Reactor Water Clean-Up System (RWCU) is important in minimizing the amount of radioactivity released to the environment in the unlikely event of an accident and in keeping occupational doses low by purifying the reactor coolant during normal operation. Presently, the RWCU system is set to isolate on a low reactor vessel water level signal to prevent draining the reactor and uncovering fuel during a LOCA event. A low reactor vessel water level will also generate a reactor scram. Plant operations personnel at Millstone Unit No. 1 have expressed the desire to lower the RWCU isolation setpoint to the low-low water level, in order to have the RWCU system available for decay heat removal and reactor water clean-up following a reactor scram.

By letter dated September 6, 1985, NNECO proposed to evaluate the feasibility of lowering the isolation setpoint together with the potential radiological consequences, adverse equipment qualification impacts following a break in the RWCU piping with the reduced isolation setpoint and alternative leak detection methods. Lowering the RWCU system isolation setpoint is also addressed in ISAP Topic 1.43, Section 3.2.43 as a means for providing system availability for reactor vessel fill. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO stated that this project would be conducted in two phases. The first phase would involve an evaluation of the feasibility of lowering the RWCU isolation setpoint and the second phase would evaluate alternative methods for detecting leakage from the RWCU system.

NNECO's estimate for the public safety attribute for this topic indicated that lowering the isolation sepoint and providing additional leakage detection capability would provide little improvement in risk reduction. Lowering the setpoint could result in a reduced probability of water hammer in the system leading to pipe failure. This would result in improved personnel safety and performance. Although the integrated value score is relatively low, the cost for performing the study and implementing the results should be very low.

The staff finds that this proposed study should have medium implementation priority. The implementation priority of any plant modifications should be determined by NNECO when the study is complete.

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3.3.73 Topic 2.21, 480V Load-Center Replacement of Oil-Filled Breakers

The overcurrent trip device, in the 480V power circuit breakers, are electro-mechanical devices that have worn with age and have decreased in reliability. The devices are oil-filled and can, if a leak develops, cause false tripping of the breakers. This could result in a safety-related piece of equipment being unavailable when needed. By letter dated October 1, 1985, NNECO proposed to replace the existing Type EC overcurrent trip devices with a solid state design. The scope of proposed project will include the engineering, design and procurement of material including qualification of the solid state devices to Category 1 standards. As an interim measure, the existing devices were rebuilt during the 1984 refueling outage at Millstone Unit No. 1. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO stated that removing the present oil filled breakers and replacing them with solid state devices is expected to improve the reliability of safety-related systems and the number of false breaker trips could be reduced. However, the PSA found that breaker opening/closing failures were the dominant contributor to 480V power supply unavailability and the probability of false breaker trip is only 5% of that unavailability. False breaker trip can be to reset by the operator and breaker degradation is generally detectable during routine maintenance.

NNECO estimated the ARM score for this topic to be 0.4, a low priority score due primarily to low public safety impact. The staff agrees with this priority ranking (although one side benefit not evaluated was the reduced fire load using solid state trip devices). This topic if implemented may be done over a protracted period of time.

3.3.74 Topic 2.22, Control Rod Drive System (CRD) Water Hammer

Reacting to a report from a CRD system vendor, the BWR Owners Group formed a committee to investigate the potential for water hammers occuring in the scram inlet lines. By letter dated August 13, 1985, NNECO stated that, based on the recommendations of the BWR Owners Group committee, they were currently evaluating water hammer loads in the CRD piping due to scram events. By letter dated January 3, 1986 (Generic Letter 86-01), the staff identified concerns associated with pipe breaks in BWR scram systems. In the letter staff stated that:

> "The design basis of SDV piping system has considered transient forces resulting from the worst case control rod drive (CRD) system actuation. Although water hammer has been analytically postulated and hydraulic instabilities have been experienced in the CRD system, no events have been experienced of a severity significant enough to constitute a water hammer. Therefore, water hammer is not considered a contributing factor in potential SDV pipe breaks."

Therefore, based upon the staff's conclusions presented in Generic Letter 86-01, the staff concludes that this proposed study need no longer be considered in ISAP.

However, in their July 31, 1986, letter, NNECO states that it is planning to continue evaluating water hammer loads in CRD piping. NNECO rated this topic to have the highest priority on their evaluation list. The staff disagrees with this rating, and finds that if this topic is to be evaluated, its schedule should be commensurate with a low priority rating.

3.3.75 Topic 2.23, Instrument, Service and Breathing Air System Improvements

The station air systems provide clean dry air for pneumatic controls and utility air for pneumatic tools, filter system, tanks and emergency breathing air. The instrument and service air systems at Millstone Unit No. 1 have historically required substantial maintenance. Contaminants including rust/scale, dryer dessicant and "loctite" have been found on valve actuators which have hampered valve actuation. By letter dated August 13, 1985, NNECO proposed a plant initiative project to perform an engineering review of the Millstone Unit No. 1 instrument, service and breathing air systems to improve reliability and integrity during both normal and emergency operating conditions.

In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO stated that it had performed an evaluation of the air systems at Millstone Unit No. 1. The evaluation resulted in a series of recommendations of improvements for modifications to the air systems. These improvements include:

(1) Replace existing air dryers, instrument air prefilters and afterfilters;

(2) Install new 780 CFM oil-free compressor;

(3) Install new air receiver;

(4) Install new backup air dryer filters on outlet of new receiver;

(5) Install 50 single in-line filters at each brnach off of the main header;

(6) Install pressure gauges upstream and downstream of each filter;

(7) Repipe air supply from the Sullair compressor to supply the service air receiver;

(8) Install coalescing filter on outlet of station air receiver;

(9) Run piping from instrument air header to new breathing air system;

(10) Install new dew-point monitor at outlet of each air dryer; and

(11) Install flow monitors in instrumentation and service air headers.

NNECO's estimate of the public safety attribute score for this topic was 3.4 on a scale of -10 to +10. This score was based on the effects of moisture, dessicant and rust in the air systems on component operability (there have been two cases in 15 years of MSIV failure to close due to sticking). The economic performance, personnel safety and personnel productivity attribute scores for this topic were also positive. The staff agrees that a reliable source of instrument, service and breathing air is important to the continued safe operation of the plant and in the prevention and mitigation of accident events. The relatively high attribute scores together with a reasonably low cost of implementation give this topic a high implementation priority.

3.3.76 Topic 2.24, Offsite Power Systems

By letter dated October 1, 1985, NNECO described a plant improvement project currently being implemented at Millstone Unit Nos. 1 and 2. The project is intended to identify areas of potential weakness and the means for improving offsite power system reliability, capacity and availability. The project includes, but is not limited to:

(1) installation of a 345kV circuit breaker on one of the two Millstone Unit No. 1 offsite power lines.

(2) installation of slow speed bus transfer schemes on selected Millstone Unit No. 1 electrical buses.

(3) installation of a main generator disconnect device (circuit breaker).

Topic Item (1) has been completed. This circuit breaker will increase the reliability of the switchyard and will allow operations personnel to remotely reclose the bus following a fault in the line. The scope of this topic for the ISAP integrated assessment is the development of a priority for completing the rest of the project. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO estimated that the improvements to the offsite power systems would significantly improve public safety and that the two modifications would effect a 4.6E-5 reduction in CMF resulting in a public safety attribute score of 6.2. This high public safety attribute score, although offset by small reductions in economic performance and personnel productivity, resulted in a high implementation priority. The staff recognizes the importance of reliable sources of offsite power and agrees with the high implementation priority for this topic.

3.3.77 Topic 2.25, Drywell Temperature Monitoring System Upgrade

Drywell bulk air temperature is an input to various containment response analyses and must be verified on a periodic basis. By letter dated September 6, 1985 NNECO proposed to upgrade the drywell temperature monitoring system to monitor specific components located in the drywell. Implementation of the project is expected to facilitate verification of compliance with 10 CFR 50.49. In a letter dated March 3, 1986, the staff concurred on the scope for this topic and recommended that the licensee evaluate the potential for leakage detection provided by this instrumentation in conjunction with Topic 2.02 (Section 3.2.54) in the integrated assessment.

In a letter dated July 31, 1986, NNECO stated that use of the drywell temperature monitor, in conjunction with the proposed drywell humidity instrumentation (refer to Section 3.3.54), would not affect the level of current leakage detection systems at Millstone Unit No. 1. The ability to monitor drywell temperature as an aid to equipment qualification service life verification would have no effect on public safety.

As stated by the staff in Section 3.3.54, humidity and temperature are only indirect indication of leakage and therefore, would result in negligible ARM attribute scores. The staff ranks the implementation priority of Topics 2.02 and 2.25 as low. NNECO currently has this topic scheduled for implementation during the 1987 refueling outage.

3.3.78 Topic 2.26, Reliability Equipment

By letter date August 26, 1985, NNECO proposed a project to aid in the effort of performing less corrective maintenance and more preventive maintenance to improve plant safety and reliability. The project consists of the procurement of computerized UT instrumentation and vibration monitoring equipment. The equipment is to be utilized for performing localized nondestructive field tests on components and equipment. In a letter dated March 3, 1986, the staff concurred on the scope for this topic. In a letter dated July 31, 1986, NNECO stated that the reliability equipment has already been purchased. This topic is considered resolved.

3.3.79 Topic 2.27, Spare Recirculation Pump Motor

By letter dated September 6, 1985, NNECO stated that it is presently rebuilding a recirculation pump rotor to provide a spare rotor for Millstone Unit No. 1 to expedite, if necessary, any future recirculation pump replacement. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO stated that it did not estimate an ARM priority score for this topic. NNECO stated that implementation of this project will enable plant personnel to expedite future replacement of a recirculation pump motor as well as give the personnel involved in this topic the experience in working with a motor. The staff recognizes the importance of giving the personnel experience with the pump motor in a situation away from emergency repairs during a plant shutdown and the possibility of reducing future personnel exposures. However, the staff feels that, relative to other topics, the implementation priority for this topic should be low.

3.3.80 Topic 2.28, Long-Term Cooling Study

In the Millstone Unit No. 1 Probabilistic Safety Study, it was shown that approximately 64% of the total calculated core melt frequency is due to a failure to maintain adequate long-term decay heat removal capability, with failures of the Shutdown Cooling System and Alternate Shutdown Cooling System being the major contributors.

By letter dated August 26, 1985, NNECO proposed to perform a study of the long-term cooling capability of Millstone Unit No. 1. Further, by letter dated December 23, 1985, NNECO elaborated on the short-term actions and modeling conservatisms from which NNECO concluded that this issue does not present an immediate safety hazard. However, the staff believes that this topic continues to offer potentially substantial safety benefits that may be related to other topics; for example, but not limited to: tornado shutdown (Topic 1.02), station backfeed (Topic 1.16), ATWS (Topic 1.18), isolation condenser reliability (Topic 1.50), main condenser restoration (Topic 1.51) and loss of power event sequences. In a letter dated March 3, 1986, the staff concurred on the scope for this topic and recommended that the objectives and evaluation criteria for this study should be developed based on a comprehensive assessment of the potential relationship to related topics.

In a letter dated August 15, 1985, NNECO provided the PSA summary for this topic. The PSA summary investigated the public risk impact of improving the long-term decay heat removal capability at Millstone Unit No. 1. The public safety attribute score for this improvement was 10 on a scale of -10 to +10.

In a letter dated February 11, 1987, NNECO submitted a requantification of the Millstone Unit No. 1 PSA based upon improvements made to the plant since the PSA was initially performed. The requantification resulted in a net reduction in estimated core melt frequency from 8E-4/year to 5E-4/year. A significant portion of this reduction is due to modified procedures regarding emergency service water and LPCI pump motor bearing lube oil coding water flow testing/verification. These and other modifications offset long-term cooling reliability and success.

Long-term cooling at Millstone Unit No. 1 continues to be the major contributor to CMF. The staff ranks the implementation priority of this study as high. Any modifications resulting from the study should be evaluated for implementation priority and scheduled at a later date. Topics 1.50 through 1.52 are closely related to the issue of long term cooling and should be integrated with this study.

3.3.81 Topic 2.29, FWCI Assessment Study

In the past few years, several changes have been made to the feedwater system at Millstone Unit No. 1. During the implemenation of the changes, it was found that the logic to transfer from level control to flow

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control was different from the original system description. By letter dated September 30, 1985, NNECO proposed to initiate a study that would compare the feedwater system drawings with the as-wired system; revise drawings as necessary; compare system descriptions with the verified wiring drawing; identify the limits of operation of the control system; and review the assumptions and impact of the feedwater control system on the design basis transients. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated July 31, 1986, NNECO indicated that they did not estimate the implementation priority for this topic. NNECO and the Millstone Unit No. 1 senior resident inspector both have concluded that system description discrepancy is probably unique to this one instance. It is the staff's position that the implementation priority for this study be the same as that for Topics 1.15, FSAR Update, and 2.09, Upgrading of P&IDs (low priority).

3.3.82 Topic 2.30, MSIV Closure Test Frequency

The Millstone Unit No. 1 Reactor Protection System design incorporates an MSIV closure trip function that initiates a reactor trip when it senses MSIV closure greater than 10%. This is an anticipatory trip and is backed up by the average power range monitor and high reactor pressure trip functions. The Millstone Unit No. 1 Probabilistic Safety Study evaluated MSIV closure events and found that they contributed to 93% of the reactor transient events with main condenser unavailabile, which accounts for 2.44% of the predicted core melt frequency. Also, two out of a total of five MSIV closure events at Millstone Unit No. 1 have been caused by overtravelling of the valve during testing.

By letter dated September 30, 1985, NNECO proposed to reduce the frequency of the 10% MSIV closure testing (thereby reducing the frequency of MSIV closure events) from monthly testing to quarterly testing in conjunction with the MSIV closure stroke testing. In the integrated assessment, NNECO will evaluate the benefit of the reduction in MSIV closure event frequency against the reduction in RPS closure signal reliability. In a letter dated March 3, 1986, the staff concurred on the scope for this topic.

In a letter dated August 15, 1985, NNECO provided the PSA summary for this topic. The PSA investigated the impact of changing the MSIV testing from monthly to quarterly. NNECO concluded that by changing the test frequency, the core melt frequency would be expected to decrease by 1%, which is primarily due to a smaller frequency for MSIV closure events. The public safety attribute score for this topic is 1.5 out of 10.

The staff review of this PSA topic summary found the summary to be generally acceptable and agreed with the score for this topic and concludes that a medium implementation priority is appropriate.

3.3.83 Topic 2.31, LPCI Lube Oil Cooler Test Frequency

The Millstone Unit No. 1 PSA identified that one of the major contributors to low pressure coolant injection system unavailability is the failure of the solenoid valve controlling the low pressure coolant injection pump motor bearing lube oil cooling. Operation of the solenoid valve is presently indirectly confirmed during refueling when the low pressure coolant injection pumps are run. Due to the infrequent confirmed testing of the solenoid valves, a high probability of the valve failing to open was calculated. Unavailability of the LPCI is a part of the overall high contribution of long-term decay heat removal capability to the total calculated core melt frequency.

In a letter dated August 26, 1985, NNECO provided the PSA summary for this topic. The PSA summary investigated the impact of a change in the surveillance testing procedure of the LPCI system. The results of the PSA summary indicated that a 13% decrease in core melt frequency would result. The Public Safety Impact score for this topic was 10 on a scale of -10 to +10.

The staff review of the PSA summary confirmed that the increase is surveillance frequency would significantly reduce the core melt frequency and public risk. The staff agrees with the Public Safety Impact score for this topic.

By letter dated September 30, 1985, NNECO stated that a change in the surveillance testing procedure of the low pressure coolant injection system to confirm opening of the solenoid valve during monthly testing of the low pressure coolant injection pump was completed. Based upon this information, this topic is resolved and warrants no further action.

3.3.84 Topic 2.32, Primary Containment Pump-Back System

Millstone Unit No. 1 utilizes an open system of pressurization and venting to maintain a minimum containment pressure differential of 1 psi between the torus and the drywell. The requirement to maintain at least a 1.0 psi differential is stated in Technical Specification 3.7.A.2. This technical specification requirement lowers the amount of water that must be displaced before the energy released in the drywell can be suppressed in the torus to assure the post-LOCA suppression pool hydrodynamic forces are minimized and are consistent with the loads assumed for structural analysis of the torus. Millstone Unit No. 1's method of maintaining the 1 psi differential pressure provided that means.

In a letter dated July 31, 1986, NNECO stated that the current commitment to install the pump-back system is during the 1987 refueling outage. This system is part of a larger issue, containment purge and vent, and the staff plans to issue an SER in the near future that considers the benefits of and completion schedule for the pump-back system. This commitment should be factored into the proposed integrated schedule. The staff recommended a medium implementation priority for this topic. This topic is currently scheduled for implementation during the 1987 refueling outage.

3.3.85 Topic 2.33 - RBCCW Leak Rate Testing

The reactor building closed cooling water (RBCCW) system is relied upon for cooling the drywell equipment sump cooler, the drywell blower cooling coils, and the recirculaton pump motors. Supply of the RBCCW must pass

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through containment penetration X-23 which only has a single check valve inside containment. The return of the RBCCW passes through penetration X-24 which has a remote manual isolation valve outside containment. If the RBCCW piping line breaks inside containment, it can be isolated by the check valve (1-RC-6) and closing the remote manual isolation valve, 1-RC-15.

Containment penetrations X-23 and X-24 are not in compliance with GDCs 54 and 57 and the leak rate testing requirements of 10 CFR Part 50, Appendix J. ISAP Topic No. 2.33 addresses these regulatory requirements. The proposed project involves installation outside of containment penetration X-23, of two manual gate valves, a containment isolation valve 1-RC-16, and leak rate test connections. Modifications to penetration X-24 involve replacement of the containment isolation valve 1-RC-15, and installation of two manual gate valves and the test connections to allow leak rate tests to be performed.

In a letter dated July 31, 1986, NNECO stated that they performed a probabilistic assessment of the public safety impact of this proposed project. The specific safety concern addressed involves one of the containment isolation valves on the manual gate valves being left closed after testing. This concern was dismissed by NNECO for the following reasons. After leak rate testing, test procedures require the operator to reopen the manual gate valves. The containment isolation valves would be remotely operated by open/close switches with indicating lights located in the control room. If a valve were left closed after testing, it would prevent RBCCW system cooling of the drywell space coolers during operation. This would result in increasing drywell temperature, thus alerting the operator to check these valves. NNECO concluded that this project would have no impact on public safety. NNECO also concluded that this project would have small negative impacts on personnel safety and personnel productivity.

The isolation provisions for penetrations X-23 and X-24 were evaluated in SEP. In the IPSAR the staff concluded that modifications to penetration X-23 were not warranted. In the IPSAR Supplement the staff concluded that adequate leakage detection, remote operation of the isolation valve is possible during an accident and plant procedures describe under what circumstances this line should be isolated. The staff considered this issue to be resolved.

The remaining issue for this topic is the question of leak rate testing requirements for these penetrations.

It is the staff's position that the need for leak rate testing for penetrations X-23 and X-24 be implemented with the same medium priority as Topic 1.14, Appendix J modifications.

3.4 Additional Areas for Integration

One of the objectives of ISAP is to provide a mechanism for prioritizing all licensing actions, pending actions and licensee initiatives such that a cost-effective implementation program can be implemented. Toward that

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end, PSAs provide one of the yardsticks to help to determine the priority of each action. The PSA is used to estimate the relative change in core melt frequency and risk associated with the implementation of an action. PSAs can also be used to suggest new actions or disclose ways of reducing uncertainty in the assessment.

Recognizing the importance of a good PSA to the understanding of nuclear power plant characteristics and to the reduction in risk that may be achieved, the staff has evaluated five areas (reliability assurance, severe accidents, station blackout, Mark I containments and external events) that may help to expand the present scope of the Millstone Unit 1 PSA for a greater understanding of operating characteris tics and a possible reduction in plant CMF.

3.4.1. Reliability Assurance

A strong reliability assurance program can be beneficial to a utility because it monitors changes in equipment reliability and tracks problems that have occured at other operating plants. The Millstone Unit 1 PSA was quantified using certain equipment and human reliability assumptions. A reliability assurance program can help to assure the validity of the PSA assumptions.

One of the keystones in assuring public health and safety is a commitment for reliable and well maintained systems and components at nuclear power plants. NNECO has informally discussed its reliability assurance program with the staff in the context of its proposed living PRA program. Appendix D presents recommended elements that the staff believes should be part of a reliability assurance program. NNECO has indicated that its proposed living PRA program already includes many of those recommendations.

3.4.2 Severe Accidents

PSAs are performed to seek a better understanding of core damage sequences and to reduce their frequency and risk. Many of the dominant sequences in the Millstone Unit 1 PSA are beyond design basis accidents. The staff believes that NNECO can make several cost-effective modifications to Millstone Unit No. 1 emergency procedures and plant equipment which should have a significant effect on preventing mitigating a severe accident.

On August 8, 1985, the Severe Accident Policy Statement was published. It described how the Commission intends to resolve safety issues related to severe accidents. The Severe Accident Policy Statement states three major goals, which are: reduction of the estimated core damage; reduction of high consequence accident sequences; and reduction of fission product releases.

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In an effort to reduce estimated core damage and identify risk outliers, NNECO has completed the Millstone Unit 1 PSA (a level 1 PRA). NNECO has already made several plant and procedural modifications which were motivated by the PSA results. The modifications include:

- revised surveillance procedures for the LPCI pump motor bearing lube oil cooling;
- revised preventive maintenance program to improve the emergency service water to LPCI cross-tie valve reliability;
- modified valve operator and switch logic for MOV 1-IC-3 (isolation condenser condensate return line valve) and replaced 1-IC-3 with a smaller valve;
- corrected LPCI and core spray pump throttling procedures;
    - corrected LPCI loop selection wiring error on the LPCI system injection valves;
    - modified emergency procedures to bypass, at the discretion of the operator, potential drywell cooler lockout;
    - changed preferred power source on valve SW-9 (isolates nonessential service water cooling loads); and
    - replaced valve operator for 1-IC-1 (isolation condenser steam isolation valve).

NNECO also stated that they will continue to evaluate emergency and normal operating procedure modifications, technical specification changes, and hardware modifications using insights from the PSA.

Implementation of many of the ISAP topics will result in a reduction of core damage frequency. Both the staff and NNECO found the following ISAP topics to contribute most to estimated core melt frequency reduction:

- Topic 1.01 - Gas Turbine Generator Start Logic Modifications
- Topic 1.16 - Appendix R (Unit 1/Unit 2 Backfeed)
- Topic 1.18 - ATWS
- Topic 2.24 - Offsite Power Systems

The staff would also include the following ISAP topics in that list because of their importance to the severe accident issue, especially related to station blackout:

- Topic 1.09 - Regulatory Guide 1.97 Instrumentation (drywell spray flow measurement);
- Topic 1.17 - Replacement of Motor-Operated Valves (drywell spray)

- Topic 1.24 - Emergency Power (gas turbine maintenance program);
- Topic 1.50 - Isolation Condenser Startup/Makeup Failures;
- Topic 1.51 - Failure to Restore Main Condenser; and
- Topic 2.30 - MSIV Closure Test Frequency

3.4.3 Station Blackout, Mark I Containments and External Events

In addition to those actions already taken by NNECO in an effort to reduce core melt frequency, the staff has evaluated Millstone Unit No. 1 in the areas of station blackout, Mark I containments and external events. Specific recommendations were made by the staff and appear in Appendix D.

The implementation priority for the staff's recommendations is detailed in Appendix D and appears in Table 4-1.

3.4.1.3 External Events

Many safety assessments which have included external events (e.g. earthquakes, fire, hurricanes, tornados, flooding, transportation of hazardous materials) have estimated that external events may be important or dominant contributors to core melt frequency and risk. The potential for high offsite consequences is heightened for events such as earthquakes and hurricanes where evacuation may be impeded.

Each of the external events analyses has areas of significant uncertainty (e.g., the return period of large earthquakes) or conservatism, some areas perhaps larger than those associated with most internal event core melt frequency analyses. Because of this, the staff does not endorse the use of bottom-line numbers from external events analyses. Rather, the staff finds that important insights regarding the relative importance of failure modes and weak links can be established.

NNECO has submitted a probabilistic fire analysis and internal flooding analysis for Millstone Unit No. 1 which are under review by the staff. The staff recommends that NNECO use a state-of-the-art similar to the ESP-NOAH code package (NUREG/CR-2678) in its flooding analysis.

It is the staff's judgement for Millstone Unit No. 1 that of the external events beyond fire and internal flooding, only seismic issues warrant further analysis at this time. Although seismic concerns were reviewed under SEP, this work was strictly an audit review, not state-of-the-art-analyses.

The staff recommends that NNECO, drawing on the seismic analysis experience in SEP, perform fragility analyses to form a basis for incorporating seismic external events into the PSA. Alternatively, NNECO could perform a seismic margins analysis to find vulnerabilities. The staff ranks the implementation priority of the seismic fragility analyses as medium.

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3.4.4 Change in Operations

Stretch Power

IN 1985 and 1986, NNECO evaluated the potential for a Millstone Unit No. 1 stretch power plan. A stretch power plan would specifically consider the feasibility of various options for increasing the electrical output of the plant. Increasing electrical output was viewed by NNECO as a potentially prudent measure to be implemented in the mid-1990s to offset a projected need for increased electric capacity.

The stretch power plan evaluated by NNECO would include a detailed plant capacity feasibility study and the associated licensing effort. First, the feasibility study would be conducted to evaluate both NSSS and BOP areas of the plant to identify and quantify the benefits and risks of the proposed project. This study would also be necessary to develop a detailed plan of what modifications and analyses would be required to support an uprating of the plant. Second, the stretch power plan would require a licensee safety analysis and approval from the NRC. NNECO considered a coordinated licensing effort with other BWR owners to satisfy this element of the plan. It was envisioned that ISAP would provide the optimum framework to address the safety and regulatory issues involved in a stretch power effort in an integrated effort to determine the most feasible and cost-effective method for increasing the Millstone Unit No. 1 power rating.

Based on its evaluation of the proposed stretch power plan, NNECO has decided not to pursue this effort for Millstone Unit No. 1 at this time. Although a plan to achieve stretch power preliminarily appears to be feasible, NNECO's decision was influenced by the potential that such an effort could reduce plant safety margins at a time when the plant is being upgraded to meet internal safety goals and objectives. Moreover, there currently is excess capacity in the NU system. In conclusion, NNECO has deferred the project, subject to possible revival in two or three years. The status of safety improvement initiatives and electric supply and demand circumstances would be among the more important decision-making parameters. If revived, NNECO plans to apply ISAP methodology to evaluate and prioritize necessary studies and plant modifications.

Change to 22-24 Month Fuel Cycle

NNECO is currently investigating the impacts of increasing the projected Millstone Unit No. 1 cycle length to 22 - 24 months. This change would be made due to the replacement of the GE-7B fuel with the newer GE-8B fuel. Summarized below are those areas in which potential impacts have been or will be assessed by NNECO and the staff.

(1) Core Component Lifetimes

Increasing the nominal fuel cycle length to 24 months is not expected to have an impact on control blade or LPRM expected

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lifetimes. Enough margin exists in the lifetime predictions to allow operation for the same number of fuel cycles with 22 - 24 month fuel cycles.

(2) Electrical Equipment Qualification (EEQ)

EQ issues should be analyzed by NNECO determine if they will be impacted by an increased cycle length. In general, EQ issues are a function of temperature, pressure, and radiation variables that depend on plant physical configuration, system operation, and accident scenarios. Accident scenarios assume infinite power operation at rated capacity prior to the accident, to maximize decay heat, radiation fields, etc.

(3) Turbine Maintenance/Inspection

Turbine maintenance and inspection is not expected to be affected by the increased cycle length. The recent short turbine inspection interval requirements, due to generic concerns with GE are based on the 1.4 inch long crack above the keyway on the number 4 generator end wheel of the "B" low pressure turbine rotor. This crack was identified during the 1985 refueling outage, and was reinspected during the May 1985 turbine inspection. The inspection revealed that the crack had not grown. With the replacement of the "B" low pressure turbine rotor during the 1987 refueling outage, the recommended inspection interval is expected to be substantially longer.

By letter dated April 18, 1986, the staff concluded that, since the turbine has only been operated for three months since the end of 1985 refueling outage, Millstone Unit No. 1 may continue to operate without affecting public safety and that NNECO should follow the recommended GE inspection interval of 1.2 years. If NNECO wishes to extend the inspection interval, NNECO should provide the basis for deviating from the GE recommendation.

(4) Surveillance Testing

Daily, weekly, monthly, quarterly, and annual surveillance will not be affected by an increased cycle length. However, NNECO is evaluating the impacts of delaying refueling outage surveillances two months. Although many 18 month surveillances could be performed during mid cycle shutdowns, the Millstone Unit No. 1 PSA currently assumes a 22 month testing interval for refueling outage surveillances. The increased cycle length is expected to result in a slight increase in the calculated core melt frequency.

Three integrated primary containment leak rate tests must be performed in each 10 year service period. Since they must be conducted at 40 ±10 month intervals, they can be rescheduled to accommodate longer cycles.

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Safety-related hydraulic and mechanical snubbers are required to be demonstrated operable by performing visual inspections and functional tests. The current 18 month interval for performing these inspections and tests will need to be increased, since many of the snubbers are inaccessible during reactor operation.

(5) In-Service Inspection (ISI)

The ISI program is divided into 10-year intervals with further subdivisions of 40 month time periods within the 10 year intervals. Increasing the cycle length to 22 - 24 months could shift the performance of certain inspections to a different refueling outage to meet the 40 month interval requirements. The total amount of work will not change. Actual cycle lengths are frequently greater than two months different than projected, causing ISI schedules to be subject to change for reasons independent of this initiative.

(6) Pipe Cracks

Crack propagation calculations will need to be modified with longer cycles. It is expected that the crack depth acceptance criteria will be slightly reduced.

In summary, with the continuing replacement of the GE-7B fuel with GE-8B fuel, the period of time that the plant could continuously operate will gradually increase over the next several cycles. When NNECO decides that it wants to investigate longer fuel cycles it should prioritize the studies, licensing activity and modifications using ISAP methodology.

3.4.5 Staffing - under Commission review

In a letter dated June 13, 1986, NNECO responded to GL 86-04 by providing a detailed description of the current education program which is intended to provide the on-shift operating crew with adequate engineering and accident assessment expertise. The submittal included a discussion of the interim shift technical advisor (STA) program, which was implemented in response to the recommendations of the TMI Lessons Learned Task Force, and the evolution of the current dual role (SRO/STA) program, which was developed in response to NUREG-0737, Item I.A.1.1. NNECO stated that the individuals presently serving in the dual role capacity are qualified to provide the engineering expertise and accident assessment function, and that no changes to the STA program are necessary.

Millstone Unit No. 1 currently has 13 on-shift operators who are dual-role qualified (hold senior operator licenses and are STA-qualified). Six of these are shift supervisors (SS), six are senior control room operators (SCO), and one is a control room operator (CO). Four of the six SCOs are SS qualified, and the CO is SCO qualified. At least two operators with dual-role qualifications are on shift most of the time. Although NNECO has not committed to provide this additional expertise to the NRC, NNECO intends to continue to exceed the minimum requirements.

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The staff met with the licensee on September 25, 1986, to obtain further information on the training program and to discuss additional information the licensee considered applicable to the staff's review.

The training and requalification training at the NU nuclear plants is aided by plant specific simulators for each unit. Every six weeks each shift goes into a training mode that includes simulator training. The simulator training is conducted on a shift basis, with each member of the shift functioning in their respective roles. The dual role Shift Supervisor/STA trains in that role.

At present, the Northeast Utilities (NU) operator qualification program does not comply with the Commission's policy as statement for the dual-role SRO/STA and the advanced notice for proposed rulemaking "Degree Requirements for Senior Operators at Nuclear Power Plants," dated May 30, 1986. While the NU program provides for comprehensive experience and formal education, it does not result in a baccalaureate degree.

The staff considers this to be an issue with high implementation priority and is currently reviewing the June 13, 1986 submittal for the STA/SRO education program for Millstone Unit Nos. 1, 2 and 3 and for the Haddam Neck Plant.

3.4.6 Containment Purge and Vent Issues

On March 20, 1978, NNECO submitted a proposal to delete the Technical Specification surveillance requirement for primary containment continuous leak rating monitoring. The basis for this change was that the surveillance was impractical. The method of continuous monitoring was originally intended to be to monitor the amount of nitrogen added to the drywell to compensate for drywell leakage. Obtaining accurate results was compromised by the need to add additional nitrogen to maintain the differential pressure between the drywell and the torus and to re-inert in order to control oxygen build-up during operation.

In a letter dated October 31, 1979, NNECO informed the NRC that plant changes were being assessed which would make the existing monitoring method more accurate. It was requested that the Staff postpone its review of the proposed license amendment request.

In an April 16, 1980 letter, NNECO informed the NRC that evaluations concluded that the existing Technical Specification for continuous leak rate monitoring via nitrogen make-up could not be accomplished with either equipment or by utilizing other instrumentation. The large volumes of make-up nitrogen needed to repressurize the drywell to maintain the 1 psid between the drywell and the torus masked the relatively small volume of nitrogen required to compensate for drywell leakage. NNECO stated that in order to accurately verify containment integrity, extremely accurate monitoring of all thermodynamic parameters in the drywell and torus, which continuously vary with time, would be required. The installation of a gas flow-meter in the atmospheric control system piping was also considered, which would provide data

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on the volume of gas vented. NNECO concluded that the Technical Specification requiring continuous leak rate monitoring via nitrogen make-up was nonviable, and should be deleted.

The staff issued a Safety Evaluation Report on June 7, 1984, concerning NNECO's proposed revision to the Technical Specifications for continuous leak rate monitoring. The Staff concluded that it would be acceptable to delete Technical Specification 4.7.A.3.g, concerning continuous leak rate monitoring, if NNECO submitted an alternate Technical Specification surveillance that meets the intent of Technical Specification 4.7.A.3.g. The SER stated that "a review of pressure trends before and after initiating a nitrogen purge and vent and the trending of time periods between venting and purging can be utilized to indicate pressure response anomalies indicative of gross containment leakage." Because purge and vent data are logged routinely, a timely indication of leakage would be available. The staff noted that Millstone Unit No. 1's method of maintaining the 1 psi differential pressure between the drywell and the torus provided a means to assess gross containment leakages via trending.

On February 25, 1985, the staff issued an SER concerning containment purge/venting which concluded:

(1) Debris screens must be provided for the purge/vent valves to ensure that valve closure would not be prevented by debris which could become entrained in escaping air and steam.

(2) All purge/vent valves must close automatically on high drywell radiation signal.

In a letter dated March 19, 1985 (Reference 97), NNECO stated that a containment pump-back systems, which would be able to take suction from the torus and discharge to the drywell, eliminating the need for purging or venting to control the differential pressure between the drywell and the torus, would be installed, beginning during the 1985 refueling outage. In addition, NNECO committed to install the instrumentation necessary to continuously monitor containment leak rate. NNECO requested that Technical Specification 4.7.3.g be retained, since full compliance with it would be achieved upon the completion of the noted modifications.

In a June 28, 1985 submittal NNECO committed to install debris screens to protect the containment purge/vent valves, and to attempt to reduce the amount of containment purging/venting, which would reduce the amount of time that the purge/vent valves are open during operation. NNECO stated that either the 1.0 psi differential pressure between the drywell and the torus would be eliminated, or a torus to drywell pump-back system would be installed. Each of these measures would significantly reduce the amount of purging/venting of Millstone Unit No. 1.

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On November 20, 1985, NNECO informed the staff that a continuous leak rate monitoring system would be installed during the 1987 refueling outage. The containment pump-back system, unless cancelled due to the possible elimination of the drywell to torus differential pressure, was to be installed during the 1987 refueling outage also.

In a letter dated December 3, 1985, the staff accepted NNECO's proposal to delay the above modifications until the 1987 refueling outage. In the interim, the maintenance of the drywell to torus differential pressure and the containment inerting required by the Technical Specifications would "provide a gross measure of containment leakage integrity over and above the testing requirements in 10 CFR 50 Appendix J."

On May 2, 1986, the staff issued an SER concerning containment purging and venting. The SER restated NNECO's commitment to install debris screens in the purge/vent lines. The Staff also accepted NNECO's commitment to reduce the amount of purge/venting by installing a pump-back system, or demonstrate that the drywell to torus differential pressure was not necessary. NNECO was requested to either commit to modify the purge/vent valves to close automatically on high drywell radiation signal, or else justify the contention that other monitored parameters would isolate the valves before a high radiation signal would be generated. All of these modifications were to be completed during the 1987 refueling outage.

NNECO's July 3, 1986 submittal provided the requested additional information to justify that automatic closure of the purge/vent valves on high drywell radiation signal is unnecessary. NNECO showed that an undetected small break LOCA occurring during drywell inerting/deinerting which is small enough to prevent containment pressure from reaching the Group II isolation setpoint of 2 psig, would not exceed 10% of the guideline values of 10 CFR Part 100. The radiological consequences of such a small reactor coolant system leak would be well below the levels of regulatory concern, and the probability of such a leak occurring during the short period of time that the purge/vent valves are open with the reactor in the operating mode is exceedingly low.

Although the necessary engineering analyses and design for the continuous leak rate monitoring system, the purge/vent line debris screens, and the torus to drywell pump-back system have all progressed to support NNECO's commitments for their implementation during the 1987 refueling outage, the integrated evaluation of purge and vent-related issues has revealed that some of the modifications should not be implemented. A consensus was developed after evaluating probabilistic risk assessment insights, radiological implications, operational/plant needs, and other related factors.

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The resulting NNECO plan is to make modifications to improve containment temperature monitoring, and to implement the torus to drywell pump-back system. Gross containment leakage will be monitored by trending drywell purge frequency and duration. The purge/vent line debris screens will not be installed, and automatic closure of the purge/vent valves on high drywell radiation signal has been determined by the licensee to be unnecessary.

Originally, NNECO considered installing a sophisticated system which would continuously monitor both primary containment leak rate and temperature. It was determined that a continuous leak rate monitoring system would be very expensive (over a million dollars), would be technically very complicated, and, in fact, might not work. However, investigations resulted in the recommendation that some of the existing temperature sensors in the drywell should be replaced during the 1987 refueling outage. Data obtained from the temperature sensors will provide direct input to the plant process computer to calculate containment bulk temperature, and will provide more accurate temperature indication for use with the Emergency Operating Procedures.

NNECO will propose an alternate Technical Specification surveillance that meets the intent of Technical Specification 4.7.A.3.g, as was suggested by the Staff in their June 7, 1984 SER. Pressure trends before and after purging with nitrogen will be monitored and the time periods between successive purgings/ventings will be used to detect gross containment leakage. Plant procedures will be developed to provide the trending methodology to be employed, and the appropriate operator actions to be taken to prevent gross leakage of the primary containment atmosphere.

Even though NNECO committed to install debris screens to protect the purge/vent valves as recommended by the Staff, NNECO continues to contend that this modification will have an extremely small safety benefit, and will not provide any benefit to the operation of the plant. The probability of a LOCA occurring while the purge/vent valves are open is low. Inerting or deinerting of the drywell is limited to 24 hours each by Technical Specification 3.7.A.6.b. The installation of the torus to drywell pump-back system will greatly reduce the amount of purging/venting currently needed to maintain the 1 psi differential pressure between the drywell and the torus. Therefore, the amount of time purge/vent valves are open, providing a flow-path for entrained debris, will be reduced significantly.

A study by NNECO to determine if the 1 psi differential pressure between the drywell and the suppression chamber was necessary concluded that the requirement should be retained.

The staff currently has NNECO's July 3, 1986 submittal under review and has given this issue an interim implementation priority of medium.

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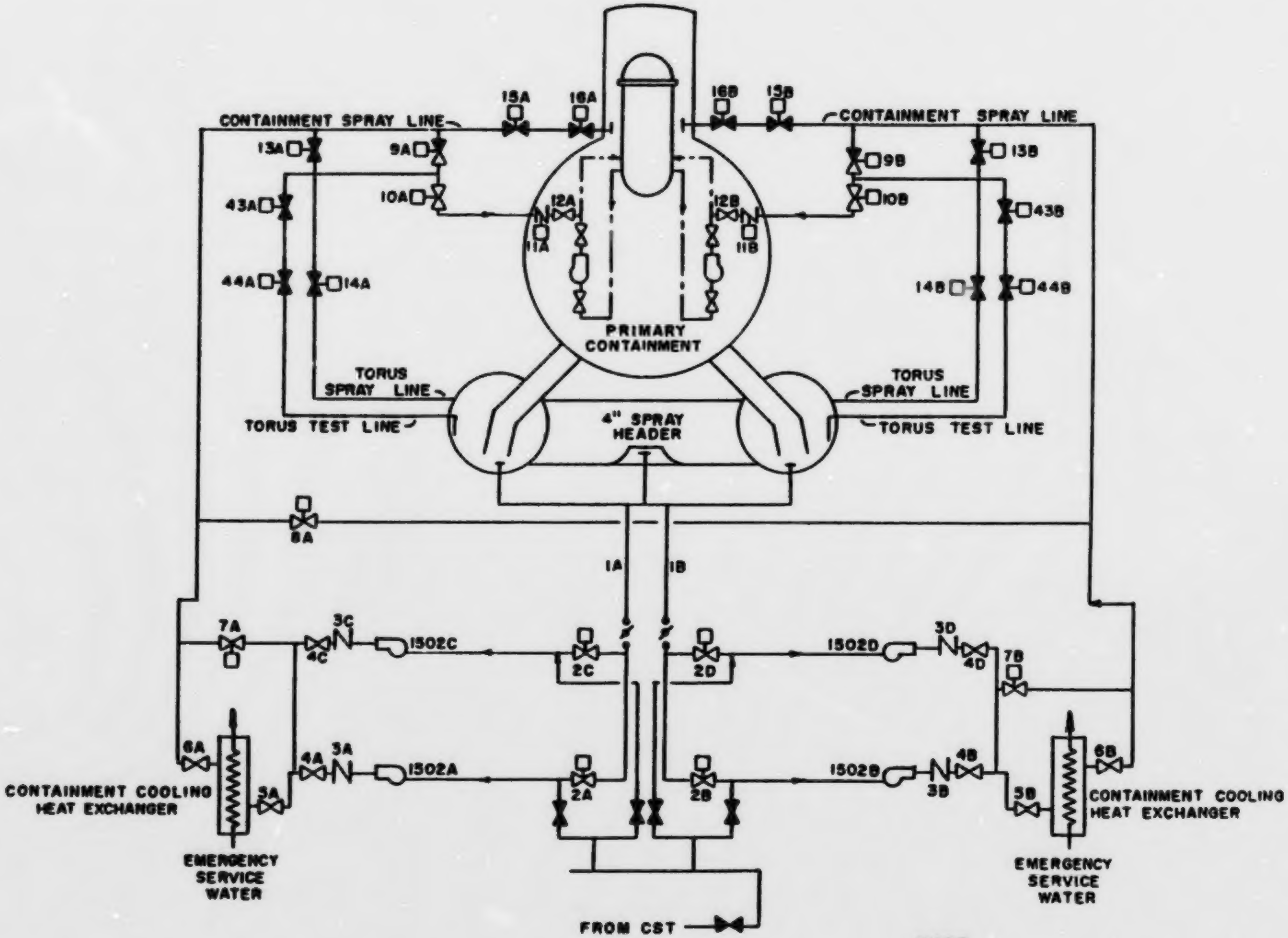
CONTAINMENT SPRAY LINE
15A
16A
16B
15B
CONTAINMENT SPRAY LINE
13A
9A
9B
13B
10A
10B
43A
43B
12A
12B
11A
11B
44A
14A
14B
44B
PRIMARY CONTAINMENT
TORUS SPRAY LINE
TORUS SPRAY LINE
TORUS TEST LINE
4" SPRAY HEADER
TORUS TEST LINE
8A
1A
1B
7A
3C
4C
1502C
2C
2D
1502D
3D
4D
7B
6A
4A
3A
1502A
2A
2B
1502B
4B
3B
5B
6B
CONTAINMENT COOLING HEAT EXCHANGER
5A
CONTAINMENT COOLING HEAT EXCHANGER
EMERGENCY SERVICE WATER
EMERGENCY SERVICE WATER
FROM CST

Figure 3.1 LPCI SYSTEM DIAGRAM

NOTE:

ALL VALVE NUMBERS
ARE PRECEEDED BY LP

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4 PRIORITIZATION OF ISAP TOPICS/IMPLEMENTATION SCHEDULE

In Section 3 of this report a description of each ISAP topic was presented together with NNECO's and the staff's perceived safety significance for each topic. The objective of an integrated assessment is to determine the implementation priority of the topics based on safety significance and implementation cost. Presented in Table 4.1 is a summary of NNECO's attribute scores and the ARM score for each topic, if applicable. Also, presented is a summary of the relative ranking of the topics by the staff. Table 4.2 is a list of those topics which were determined during the course of the ISAP review to be complete with no further actions required.

Those topics listed on Table 4.1 which were ranked high by the staff are those which the staff found to represent a high safety and/or economic benefit and should be implemented as soon as plant operations allow. Those topics which were ranked medium are those which represent desireable improvements in safety and/or economic benefit but can be implemented over a longer period of time. Those topics which were ranked low are those which represent little or no improvements in safety and/or economic benefit and should be implemented last, if at all.

It is requested that NNECO review the staff's conclusions for each topic and the relative ranking of the topics. This draft ISAR will also be presented to the ACRS and peer review experts for additional comments.

NNECO should use the relative ranking of topics in Table 4.1 in the development of an integrated implementation schedule for Millstone Unit No. 1 except where a topic has an existing scheduled completion date. The integrated schedule should encompass not only the ISAP topics, but also all implementation actions which were not deferred to ISAP and all routine licensing actions.

The staff realizes that the integrated implementation schedule will also involve uncertainties and financial constraints such that a mixture of high, medium and low topics will be implemented during any given time period. NNECO should identify any topics ranked as low that they consider of such low significance or high cost such that the topic should not be included in the integrated implementation schedule and provide justification for dropping the topic. Also, NNECO should identify any topics for which their ranking and the staff's are different and present any additional information related to their proposed ranking.

The staff will evaluate any ranking discrepancies, the issues proposed to be dropped and the integrated implementation schedule. In the event that the staff and NNECO still differ on the ranking or resolution of any topic, that difference will be aired in accordance with established NRC appeal procedures and ultimately presented to the Commission as a policy issue for action, if necessary. The resolution will appear in the final ISAR.

			NNECO						
Topic Title	ISAP Topic	ISAR Section	Public Safety	Economic Performance	Personnel Safety	Personnel Prod.	Integrated Value	ARM Score	NRC Rank
FWCI Area Coolers Electrical Modifications	1.05	3.3.5	10.00	0.00	0.00	0.00	3892	7.66	High
RG 1.97 - Drywell Spray Flow	1.09.5	3.3.9					-4 to 0		High
Unit 1/2 Backfeed	1.16.1	3.3.16	5.25	0.00	0.00	-0.50	2043	1.16	High
Cable Vault Halon System	1.16.7	3.3.16	2.60	0.00	0.20	-1.00	1017	2.52	High
Control Room Halon System	1.16.8	3.3.16	1.20	0.00	0.00	-1.00	506	1.15	High
Replacement of Motor Operated Valves	1.17	3.3.17	0.15	0.00	0.00	0.00	58	0.08	High
Spent Fuel Pool Storage Racks/Transporation Cask	2.18	3.3.70	0.00	10.00	0.00	0.00	9612	1.10	High
Instrument, Service and Breathing Air Imprv.	2.23	3.3.75	3.40	1.00	3.00	2.00	2333	4.52	High
Offsite Power Systems	2.24	3.3.76	6.20	-0.01	0.00	-1.00	2404	8.01	High
Long Term Cooling Study	2.28	3.3.80	10.00	0.00	0.00	0.00	3892	0.63	High
Station Blackout		3.4.1.2.1.1							High
Drywell Spray Function		3.4.1.2.1.2							High
Wetwell Venting Function		3.4.1.2.1.2							High
Prevent Deinerting		3.4.1.2.1.2							High
Primary System Injection		3.4.1.2.1.2							High
Staffing		3.4.3							High
Tornado Missile Protection	1.02	3.3.2	3.75	0.00	0.00	-1.00	1460	2.53	Medium
Safety Parameter Display System	1.08	3.3.8	1.00	0.50	0.00	2.00	870	0.06	Medium
RG 1.97 - RPV Water Level	1.09.2	3.3.9					-4 to 0		Medium
RG 1.97 - Neutron Flux	1.09.3	3.3.9					-4 to 0		Medium
RG 1.97 - Drywell Temperature	1.09.4	3.3.9					-4 to 0		Medium
RG 1.97 - Primary Cont. Isolation Valve Position	1.09.8	3.3.9					-4 to 0		Medium
Post Accident Hydrogen Monitor	1.11	3.3.11							Medium
Control Room Habitability	1.12	3.3.12	0.50	0.10	-2.60	-2.00	262	0.05	Medium
BWR Vessel Water Level Instrumentation	1.13	3.3.13	1.50	0.00	0.00	0.00	584		Medium
Appendix J Modifications	1.14	3.3.14	0.00	2.00	0.00	0.00	18	0.03	Medium
Cooling Control Rod Drive Pumps	1.16.2	3.3.16	5.25	0.00	0.00	-0.50	2043	1.16	Medium
Hydrogen System Modifications	1.16.11	3.3.16	0.00	0.00	3.00	0.00	38	0.59	Medium
ATWS	1.18	3.3.18	1.00	0.00	0.00	0.00	389	0.91	Medium
Integrated Structural Analysis	1.19	3.3.19					NC		Medium
Fault Transfers	1.21	3.3.21	-0.25	0.00	0.00	0.00	-97		Medium
Grid Separation Procedures	1.23	3.3.23					NC		Medium
Emergency Power	1.24	3.3.24					NC		Medium
Degraded Grid Voltage Procedures	1.25	3.3.25					NC		Medium

Table 4.1 Relative Ranking of ISAP Issues

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Topic Title	ISAP Topic	ISAR Section	Public Safety	Economic Performance	Personnel Safety	Personnel Prod.	Integrated Value	ARM Score	NRC Rank
				NNECO					
Flooding of Compartments by Backflow	1.41	3.3.41					NC		Medium
Isolation Condenser Startup/Makeup Failures	1.50	3.3.50					NC		Medium
Failure to Restore Main Condenser	1.51	3.3.51					NC		Medium
Safety/Relief Valve Failure/Setpoint Drift	1.52	3.3.52					NC		Medium
Process Computer Replacement	2.03	3.3.55	1.00	0.50	0.00	2.00	870	0.06	Medium
Hydrogen Water Chemistry Study	2.05	3.3.57					NC		Medium
Condenser Retube	2.06	3.3.58	1.25	3.50	3.50	5.00	3912	0.23	Medium
Extraction Steam Piping	2.08	3.3.60	1.75	5.60	4.40	1.00	6171	0.44	Medium
Drywell Ventilation System	2.10	3.3.62	0.05	0.50	1.00	0.50	509	0.21	Medium
Torque Switch Evaluation for MOVs	2.15	3.3.67					NC		Medium
4.16kV, 480V & 125Vdc Plant Distribution Prot.	2.17	3.3.69	0.10	0.00	0.00	0.00	39		Medium
RWCU System Isolation Setpoint Reduction	2.20	3.3.72	0.00	0.00	1.00	1.00	9		Medium
MSIV Closure Test Frequency	2.30	3.3.82					NC		Medium
Primary Containmet Pump-Back System	2.32	3.3.84	0.00	0.00	-0.50	-1.00	-6	-0.01	Medium
RBCCW Leak Rate Testing	2.33	3.3.85	0.00	0.00	-0.50	-1.00	-6	-0.01	Medium
Station Blackout		3.4.1.2.1.1							Medium
Operator Response During ATWS		3.4.1.2.1.2							Medium
Emergency Core Cooling Injection		3.4.1.2.1.2							Medium
Seismic Margins Analysis		3.4.1.3							Medium
Containment Purge and Vent Issues		3.4.4							Medium
Gas Turbine Generator Start Logic Modifications	1.01	3.3.1	1.00	1.20	0.00	0.00	1543	21.73	Low
Containment Isolation-Appendix A Modifications	1.03	3.3.3	0.00	0.00	0.00	0.00	0	0.00	Low
Intake Structure Exhaust Fans	1.05	3.3.5						0.00	Low
Seismic Qualification of Safety Related Piping	1.06	3.3.6	0.10	0.00	-1.70	-2.00	24	0.00	Low
*	1.07	3.3.7	0.10	0.10	0.00	0.00	135		Low
RG 1.97 - RPV Pressure	1.09.1	3.3.9					-4 to 0		Low
RG 1.97 - IC Shell Side Water Level	1.09.6	3.3.9					-4 to 0		Low
Emergency Response Facilities Instrumentation	1.10	3.3.10	1.00	0.00	0.00	0.00	389	0.52	Low
FSAR Update	1.15	3.3.15	0.25	0.00	0.00	2.00	98	0.03	Low
Cooldown without Service Water	1.16.3	3.3.16	0.00	0.00	0.00	0.00	0	0.00	Low
Modify Drywell Penetrations	1.16.4	3.3.16	1.00	0.50	0.00	2.00	870	0.06	Low
Curbs, Ramps and Seals	1.16.5	3.3.16	0.00	0.00	0.50	0.00	6	0.02	Low
Water Curtains/Steel Enclosures	1.16.6	3.3.16	0.10	0.00	0.50	-1.00	45	0.17	Low

Table 4.1 Relative Ranking of ISAP Issues (Cont.)

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			NNECO						
Topic Title	ISAP Topic	ISAR Section	Public Safety	Economic Performance	Personnel Safety	Personnel Prod.	Integrated Value	ARM Score	NRC Rank
Fire Barriers	1.16.9	3.3.16	0.00	0.00	0.00	-0.50	0	0.00	Low
MSIV/ADS Circuit Protection	1.16.10	3.3.16	0.01	0.00	0.00	0.00	4	0.01	Low
Emergency Lighting Modifications	1.16.12	3.3.16	0.14	0.00	0.20	-0.50	59	0.09	Low
Electrical Isolation	1.22	3.3.22	0.00	0.00	0.00	0.00	0		Low
Item 2.1-Equipment Classification/Vendor Inter.	1.26	3.3.26					NC		Low
Item 2.2-Equipment Classification/Vendor Inter.	1.31	3.3.31					NC		Low
Items 4.5.2&.3-Reactor Trip System Testing	1.34	3.3.34					NC		Low
TS Covered by GL 83-36	1.36	3.3.36					NC		Low
Expand QA List	1.38	3.3.38					NC		Low
Radiation Protection Plans	1.39	3.3.39					NC		Low
Bolting Degradation or Failure	1.40	3.3.40					NC		Low
Water Hammer	1.43	3.3.43							Low
Containment Emergency Sump Performance	1.47	3.3.47					NC		Low
Safety Factor for Penetration X-10A	1.48	3.3.48					NC		Low
LPCI Remotely Operated Valve 1-LP-50A&B	2.01	3.3.53	0.10	0.00	0.00	-1.00	39	0.19	Low
Drywell Humidity Instrumentation	2.02	3.3.54	0.05	0.00	1.50	-0.50	32	0.02	Low
High Steam Flow Setpoint Increase	2.04	3.3.56	-0.05	0.32	0.00	0.00	288		Low
Upgrading of P&IDs	2.09	3.3.61	0.10	0.00	1.20	2.00	49	0.05	Low
Stud Tensioners	2.11	3.3.63	0.00	1.00	3.30	1.00	1009	1.28	Low
Reactor Vessel Head Stand Relocation	2.12	3.3.64	0.00	0.08	5.10	0.50	255	3.15	Low
Reactor Protection Trip System	2.16	3.3.68	0.00	0.00	0.00	0.00	0	0.00	Low
480V Load Center Repl. of Oil Filled Breaker	2.21	3.3.73	0.00	0.00	0.50	1.00	6	0.04	Low
Control Rod Drive System Water Hammer Analysis	2.22	3.3.74	0.00	1.00	0.00	0.00	961		Low
Drywell Temperature Monitoring System Upgrade	2.25	3.3.77	0.05	0.00	1.50	-0.50	32	0.02	Low
Spare Recirculation Pump Motor	2.27	3.3.79					NC		Low
FWCI Assessment Study	2.29	3.3.81					NC		Low
Supression Pool Bypass		3.4.1.2.1.2							Low
Reactor Pressure Vessel Depressurization		3.4.1.2.1.2							Low
Change to 22-24 Month Fuel Cycle		3.4.2							[illegible]

It should be noted that the NRC Rank is the priority of the individual topic in relation to all other topics as proposed by the staff. NNECO will be asked to comment on the proposed ranking, to provide an integrated schedule for all plant activities using the rankings and to justify why any topics, if any, were not included in the schedule.

Table 4.1 Relative Ranking of ISAP Issues (Cont.)

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Topic Title	ISAP Topic	ISAR Section	Status
RWCU System Pressure Interlock	1.04	3.3.4	Complete
MOV Interlocks	1.20	3.3.20	Complete
Items 3.1.1&.2-Post Maintenance Testing	1.27	3.3.27	Complete
Item 3.1.3-Post Maintenance Testing TS Changes	1.28	3.3.28	Complete
Response to GL 81-34	1.29	3.3.29	Complete
Item 1.2-Post Trip Review Data and Information	1.30	3.3.30	Complete
Items 3.2.1&.2-Post Maint. Testing Procedures	1.32	3.3.32	Complete
Item 3.2.3-Post Maintenance Testing TS Changes	1.33	3.3.33	Complete
Item 4.5.1-Reactor System Functional Testing	1.35	3.3.35	Complete
TS Affected by 50.72 and .73 (GL 83-43)	1.37	3.3.37	Complete
MSL Leakage Control Systems	1.42	3.3.42	Complete
Asymmetric Blowdown Loads on Reactor Systems	1.44	3.3.44	Complete
Systems Interaction	1.45	3.3.45	Complete
Determination of SRV Pool Dynamic Loads	1.46	3.3.46	Complete
Reactor Vessel Surveillance Program	1.49	3.3.49	Dropped
Sodium Hypochlorite System	2.07	3.3.59	Complete
Turbine Water Induction Modifications	2.13	3.3.65	Dropped
Evaluation and Implementation of NUREG-0577	2.14	3.3.66	Complete
DC System Review	2.19	3.3.71	Dropped
Reliability Equipment	2.26	3.3.78	Complete
LPCI Lube Oil Cooler Test Frequency	2.31	3.3.83	Complete
Stretch Power		3.4.2	Dropped

Table 4.2 Topics Which Have Been Completed or Dropped

5 REFERENCES

Code of Federal Regulations, Title 10, "Energy" (10 CFR) (includes General Design Criteria).

Letter, September 1, 1972, from NNECO to NRC, re: FTOL conversion

---, March 20, 1978, from D. C. Switzer (NNECO) to D. L. Zieman (NRC), "Proposed Technical Specification Changes".

---, October 31, 1979, from W. G. Counsil (NNECO) to D. L. Zieman (NRC), "Containment Monitoring".

---, April 16, 1980, from W G. Counsil (NNECO) to D. L. Zieman (NRC), "Primary Containment Continuous Leak Rate Monitoring".

---, December 2, 1981, from D. M Crutchfield (NRC) to W. G. Counsil (NNECO), "Water Hammer - Millstone Unit 1".

---, July 7, 1982, from G. C. Lainas (NRC) to W. G. Counsil (NNECO), "Unresolved Safety Issues Status for the Millstone Nuclear Power Station, Unit No. 1".

---, August 30, 1982, from D. M. Crutchfield (NRC) to W. G. Counsil (NNECO), "Isolation Condenser Water Hammer Events".

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APPENDIX A

COMMISSION POLICY STATEMENT

NUCLEAR REGULATORY COMMISSION

10 CFR Part 50

Commission Policy Statement on the Systematic Safety Evaluation of Operating Nuclear Power Reactors

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of Commission Policy Statement.

SUMMARY: This Policy Statement describes a pilot program for which the Commission has developed the regulatory policies and practices to conduct integrated assessments for operating nuclear power reactors. This program is called the Integrated Safety Assessment Program (ISAP) and will address significant regulatory requirements which have evolved since the plant was originally licensed and pending licensing actions which have evolved from a variety of other sources. An integrated assessment will be conducted on a plant-specific basis, as part of a trial program, to evaluate all licensing issues on a given facility and to establish schedules for any necessary plant improvements. In addition, procedures have been established to allow for a periodic updating of the resulting implementation schedules for new licensing issues that arise in the future.

FOR FURTHER INFORMATION CONTACT: Dennis M. Crutchfield, Assistant Director for Safety Assessment, Division of Licensing, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, Telephone (301) 492-7492.

SUPPLEMENTARY INFORMATION: In 1977, the Nuclear Regulatory Commission initiated the Systematic Evaluation Program (SEP). Phase I of SEP defined a specific set of safety issues (topics) to be reviewed for operating nuclear power plants. Phase II of SEP was a pilot review of those topics for eleven of the oldest domestic operating reactors. Results have evolved from SEP over the last two years and identified significant experience relative to the safety and evaluation techniques for operating plants.

In 1980, Congress enacted Pub. L. 96-295 (the NRC Authorization Bill for Fiscal Year 1980). Section 110 of Pub. L. 96-295 required that the NRC develop a program for the systematic safety evaluations of operating reactors. The program proposal would have extended SEP to an evaluation which required licensees to compare their plant design to the acceptance criteria in the

Standard Review Plan (NUREG-0800).* hat program was not implemented for operating reactors; the Commission determined, and the Congress agreed, that the scope of the program was too broad to efficiently evaluate the safety of operating reactors. Congress subsequently specified in later Authorization Bills that funds should not be spent to implement that program. However, those activities were useful in that they focused attention on the needs and difficulties associated with the systematic safety evaluation of operating reactors as they relate to a constantly changing technology and increasing scope of regulatory requirements.

Following the TMI-2 accident, the NRC developed the TMI Action Plan (NUREG-0660)* from the safety lessons learned. Two aspects of the TMI Action Plan are particularly significant to the evaluation of the safety of operating plants: (1) it identified a large number of corrective actions to be implemented by operating plants and (2) it initiated the Interim Reliability Evaluation Program (IREP) in which plant-specific probabilistic risk assessment (PRA) studies were to be performed by the staff for several operating reactors to upplement the risk-reliability experience from the Reactor Safety Study (WASH-1400). The licensing actions resulting from TMI have increased the scope of outstanding licensing issues for all operating plants. Similarly, the experience thus far from IREP indicates that there are plant-specific strengths and weaknesses, from a reliability point of view, that warrant further consideration, beyond the deterministically-based issues.

One of the most significant conclusions drawn from SEP and IREP is that issues related to safety of operating nuclear power plants can be more effectively and efficiently implemented in an integrated, plant-specific review. In addition, the experience from SEP has served to focus on the set of current licensing criteria which should be evaluated for operating plants and experience from IREP has served to define the methods to conduct a plant-specific probabilistic safety analysis so that consistent, comparable results could be obtained which would enhance an integrated plant safety assessment.

Historically, licensing issues have been evaluated generically, and guidelines for any necessary corrective actions have been applied uniformly to all plants. While this approach has provided an effective means to ensure resolution of these issues, the generic implementation has not given sufficient attention to plant-specific characteristics which have a direct bearing on the appropriateness of the corrective action and the relative importance of the issue in relation to an overall plan for any necessary plant improvements. In some cases, consideration of plant-specific characteristics have identified alternative corrective actions which provide an equivalent or greater measure of safety, often at less cost to the licensee.

Consequently, the NRC had developed the regulatory procedures and attendant policies to conduct integrated assessments for operating power reactors. This approach is called the Integrated Safety Assessment Program (ISAP). In order to ensure the effectiveness of this program, it will be started on a trial basis and the plants to be reviewed have been selected by the NRC Staff from those licensees who indicated an interest to voluntarily participate in such a program.

Based on the results of this trial program, the NRC will decide, in about a year, whether or how this program should be extended to other operating reactors.

Implementation Schedules

To provide a stable environment to conduct ISAP, the Commission has authorized the staff to suspend specific existing implementation schedule requirements for the plants to be reviewed. Each affected licensee will be expected to propose and justify deferral for specific implementation requirements that warrant further evaluation. The associated implementation requirements and other safety issues will be evaluated collectively in an integrated assessment. The staff is only authorized to defer substantive regulatory and other requirements to the extent allowed by the Commission's procedural regulations. Thus, the staff will use the provisions in 10 CFR 50.12 to grant any exemptions.

In addition, any new implementation requirements which evolve late in the course of or following ISAP will be deferred for the plants involved and incorporated in an implementation schedule update, as described below.

The only exceptions will be issues for which the NRC Staff explicitly determines that prompt action is required to protect the health and safety of the public. Such actions include the short-term response to bulletins issued by the Office of Inspection and Enforcement.

Scope of Evaluation

The scope of ISAP is intended to be as comprehensive as practical. Consequently, it will consist of deterministic, probabilistic, and operating experience evaluations, which will serve to identify specific issues to be addressed in an integrated assessment.

The deterministic review areas, or ISAP topics, will be derived on a plant-specific basis during a screening review with the licensee at the beginning of the program. The issues to be considered are (1) a set of SEP Topics for which the NRC Staff has found significant differences between current licensing criteria and typical design criteria in existence when operating plants were licensed; (2) all pending licensing actions for the plant, including multi-plant actions, TMI Action Plan requirements and plant-specific licensing actions; (3) the unresolved generic issues for which resolution on a plant-specific basis might be expected, and (4) plant improvements proposed by the licensee.

The Commission's Safety Goal Policy published on March 14, 1983, (48 FR 10772), indicates that the quantitative goals and design objectives will not be used in the licensing process during the evaluation period, nor will the policy be interpreted as requiring that licensees or applicants perform a probabilistic analysis; however, the Commission continues to believe that probabilistic analyses provide a valuable adjunct to the deterministic regulatory requirements and enhance engineering judgments, if they are properly performed and applied. Consequently, the Commission believes that a plant-specific probabilistic safety assessment (PSA) should be performed in conjunction with ISAP. The plant-specific PSA will provide a basis for cost/benefit evaluations for the deterministically-based issues and will also identify potential strengths and weaknesses in the plant design and operation which should be considered in an integrated assessment.

An operating experience evaluation will be conducted in parallel with the topic evaluations and plant-specific PSA. This evaluation will be used to identify issues related to significant trends, event precursors, plant management and operation, and maintenance practices. In addition, the operating experience evaluation will provide a diverse perspective for the integrated assessment. The evaluation will consist of an analysis and categorization of reportable events and forced plant shutdowns and an evaluation of overall licensee performance.

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Evaluation Process

The ISAP Topic evaluations and plant-specific PSA will be conducted in parallel. The licensee will initially perform deterministic analyses for the plant-specific set of ISAP Topics by comparing the as-built design of the facility to the current licensing criteria, industry codes and standards, or other appropriate acceptance criteria and also provide risk perspectives for each issue based on the PSA. The staff will review the licensee's analyses and issue safety evaluation reports which identify specific differences from the acceptance criteria and any attendant safety issues which should be considered in the integrated assessment. Schedules for the licensee's analyses and staff evaluation will be established during the screening review to enhance an efficient use of resources.

A PSA would be conducted by the licensee in accordance with an NRC Procedures Guide (NUREG/CR-2815). The Procedures Guide describes appropriate and consistent methods for (1) initiator definition, (2) application of data, (3) success/failure criteria, (4) analysis, (5) quality control, and (6) documentation and presentation of results. In addition, the NRC Staff will identify methods by which the PSA should address unresolved generic issues; i.e., safety issues for which acceptance criteria do not yet exist. During the screening review, milestones will be established to monitor the progress of the PSA and to ensure appropriate interaction between the NRC Staff and the licensee. The licensee will be expected to use the PSA to identify significant contributors to risk that should be specifically considered in the integrated assessment. For the trial program, the extent and nature of plant-specific probabilistic analyses will be established on a case-by-case basis.

The issues raised in the ISAP Topic evaluations and the PSA, and the operating experience evaluation will be considered collectively in an integrated assessment. Decisions on corrective actions will be based on qualitative assessments of the value and impact of each action. The NRC Staff will present its conclusions regarding the need for or appropriateness of corrective actions proposed by the licensee for each of the identified issues in a draft report. The draft report will be issued for public comment and peer review. Should the NRC Staff and licensee disagree on the corrective action for any issue, that matter will be resolved in accordance with the Commission's procedures for backfitting requirements.

Following resolution of any comments on the draft report, the NRC Staff will request that the licensee establish and justify implementation schedules for each of the corrective actions and any ongoing analyses that may be necessary to establish appropriate corrective actions. The NRC Staff will judge the adequacy of the proposed implementation schedules based on the technical evaluation of the issues presented in the draft report and issue an implementation plan in a final report.

Licensing Action and Schedule Updates

The final report will serve as the basis and documentation for a license amendment incorporating and formalizing the implementation schedules. The license amendment will also establish procedures to periodically update the implementation schedule.

Any new implementation requirements that arise during or following an ISAP review will be deferred, except for those issues for which the NRC Staff determines that prompt action is required to ensure the health and safety or common defense and security of the public.

The deferred implementation requirements will be evaluated collectively as part of an implementation schedule update. The update evaluations would be conducted periodically, but not more than at five-year intervals. The evaluation would follow the same general course as an ISAP review and would consider a revised PSA, which has been updated to reflect corrective actions and plant improvements as they are completed. The revised implementation schedule will similarly be incorporated and formalized by a new license amendment.

Dated at Washington, D.C., this 9th day of November 1984.

For the Nuclear Regulatory Commission.
Samuel J. Chilk,
Secretary of the Commission.

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APPENDIX B

OPERATING EXPERIENCE REVIEW

ORNL/NOAC-228

Technical Evaluation Report
on
REVIEW OF THE OPERATING EXPERIENCE HISTORY THROUGH 1984 OF MILLSTONE 1 FOR THE NUCLEAR REGULATORY COMMISSION'S INTEGRATED SAFETY ASSESSMENT PROGRAM

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REVIEW OF THE OPERATING HISTORY OF MILLSTONE UNIT 1 THROUGH 1984

EXECUTIVE SUMMARY

The Systematic Evaluation Program Branch of the Nuclear Regulatory Commission (NRC) is conducting a pilot program for the Integrated Safety Assessment Program (ISAP), in which all pending licensing actions and safety issues for a selected operating reactor will be evaluated. A new approach to addressing a growing need for order and efficiency in the implementation and resolution of licensing requirements for operating nuclear power plants is being evolved under this program.

The new ISAP approach provides a structure for the regulatory management of licensing requirements on a plant-specific basis. One objective is to assure the implementation of the most effective safety measures in the near-term, while efficient use of both NRC staff and licensee resources is made. To accomplish this objective, ISAP will: (1) evaluate all applicable issues related to plant safety in accordance with a pre-established scope; (2) identify cost-effective corrective actions, where necessary, to enhance safety on a plant-specific basis; (3) establish a technical basis to judge implementation schedules, and (4) document the results of the evaluation so that the implementation schedule can be periodically updated, as necessary, to incorporate corrective actions for issues that may arise in the future.

Tools which will be utilized in the ISAP evaluation process include: (1) a deterministic review of all pending licensing actions and safety issues; (2) a plant-specific Probabilistic Safety Analysis (PSA); and (3) an evaluation of plant operating experience and reliability data, including licensee performance [e.g., from existing Safety Assessments of Licensee Performance (SALP) evaluations].

As part of the pilot program for ISAP, the NRC contracted with the Oak Ridge National Laboratory's Nuclear Operations Analysis Center (NOAC) to perform operating history reviews for two plants that have volunteered to be included: Millstone 1 and Haddam Neck Plants. These reviews will be used as an integral part of the ISAP evaluation process. Each review includes the collection and the evaluation of data on availability and capacity factors, forced shutdowns, forced power reductions, reportable events, environmental events, and radiological release events. The data is analyzed and evaluated to identify any trends and symptoms that will be important in the resolution of regulatory actions to be applied to the plant. Observations and conclusions are provided which focus on the key findings of the review.

The review of the Millstone 1 operating history incorporates the findings previously presented in the report generated under the Systematic Evaluation Program (SEP) NUREG-0824, "Integrated Plant Safety Assessment, Systematic Evaluation Program — Millstone Nuclear Power Station, Unit 1." This new report updates those findings to include data for the years 1982 through 1984.

The operating history review focuses principally on evaluations of data which is divided into two segments: (1) data on forced shutdowns and power reductions and (2) data on reportable events. In the forced shutdown and power reduction segment, the review identifies Design Basis Events (DBEs) and recurring events that may be used as indicators of potential operating concerns. DBEs are defined as those events delineated in the NRC's *Standard Review Plan*, and result from failures in systems, equipment and operator actions that initiate system transients and challenge engineered safety features. In the reportable event segment, which includes environmental events and radiological release events, the review identifies significant events and recurring events that may also be used as indicators of potential operating concerns. Significant events are classified as those events in which a degradation of safety margin occurs, such that safe operation cannot continue to be assured or in which challenges to the safety protection features of the plant resulted. Selection of significant events was accomplished using a set of criteria pre-established in the SEP reviews. The findings of the review are summarized below.

Availability and Capacity Factors

From 1971 through 1984, the cumulative values for reactor availability factor and unit capacity factor at Millstone 1 were 78.1% and 73.6% respectively, both of which are above average for commercial nuclear power plants. The reactor availability factor fell below 70% in only two years, 1973 and 1981. The major unit shutdowns in 1973 were for refueling and for feedwater sparger replacement. Combined, these shutdowns accounted for over five months of downtime. In 1981, shutdowns for refueling and for balancing of the turbine, combined, accounted for over five months of downtime.

Of particular note, although outside the scope of this review, is the fact that Millstone 1 accomplished 374 consecutive days of operation before shutting down automatically on August 13, 1985.

Forced Shutdowns and Power Reductions

Of the 202 forced shutdowns and power reductions which occurred between 1971 and 1984 at Millstone 1, 56 are categorized into 11 types of DBE:

1. Turbine trip (34 events),
2. Steam pressure regulator failure resulting in increased steam flow (3 events),
3. Steam pressure regulator failure resulting in decreased steam flow (3 events),
4. Loss of normal feedwater (3 events),
5. Inadvertent opening of a safety or relief valve (3 events),
6. Increased feedwater flow (3 events),

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7. Loss of external electric load (2 events),
8. Inadvertent closure of main steam isolation valve (MSIV) (2 events),
9. Decreased feedwater temperature (1 event),
10. Loss of condenser vaccum (1 event), and
11. Reactor recirculation pump trip (1 event).

Forty-nine of these fifty-six DBEs occurred as a result of equipment failures. Human error caused the remaining seven events. In all the DBEs, engineered safety features were reported to operate properly in the mitigation of the transient.

The rate of occurrence of DBEs averaged about 5 per year over the operating history at Millstone 1. The largest number of events in a single year (24) occurred in 1971. There were only two DBEs occurring during the entire period of the last three years covered by the review (1982 through 1984). The frequency of occurrence of each type of DBE is consistent with the experience of other plants, except for turbine trips. Problems with moisture separator drain tank level control during power changes were the primary causes of turbine trips (21 of 34 events). However, the rate of recurrence of these problems decreased with time (14 events per year in 1971 falling to 1 event per year in 1981).

An increase in the rate of recurrence of power reductions since 1980 was caused by the need to locate and repair leaking main condenser tubes. Such leakage results in increased volumes of radioactive waste (radwaste) products generated from the condensate and clean-up system demineralizer. Thus, when it became more difficult to dispose of radwaste products, it was very important to reduce condenser tube leaks. Also, as a side benefit, there was a consequential reduction in occupational exposure to individuals who would otherwise have had to handle and dispose of spent resins.

Reportable Events

A total of 404 reportable events, which occurred at Millstone 1 from 1971 through 1984, were reviewed. The rate of generation of event reports over the period under review is generally stable, peaking in the years 1977, 1979, 1981, and 1983 with 38, 36, 44, and 39 events respectively. Inherent equipment failure was reported as the primary cause of 56% of the total number of events. Human error (including administrative, design, fabrication, installation, maintenance, and operator error) was reported as the primary cause of another 43% of this total. Other causes, such as adverse environmental conditions, accounted for the remaining 1%. There is no apparent trend in the causes of reportable events.

Only thirteen of the 404 reportable events are classified as significant. These are:

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- Loss of the isolation condenser (1 event),
- Loss of provisions for emergency core cooling during a loss of normal power (2 events),
- ECSS failures (2 events),
- Loss of offsite power with partial loss of emergency power (1 event),
- Loss of emergency power (2 events),
- Inadvertent criticality (1 event),
- Replacement of control rod drive accumulators (1 event),
- Recirculation pump trip with no alarm given (1 event),
- Loss of pressure control followed by a blowdown (1 event), and
- Hydrogen explosion in the off-gas system (1 event).

Human error was reported to be the cause of 11 of these 13 events. The remaining 2 events were reported to be caused by equipment failures. All 13 significant events occurred in the years before 1982.

The data shows repeated reports of certain specific operating problems. These recurrences fell principally in eight types of events:

1. Loss of emergency power supply,
2. Excessive cooldown,
3. Pipe crack,
4. Isolation condenser valve failure,
5. MSIV failure,
6. Safety/relief valve setpoint drift,
7. Stack gas monitor failure, and
8. Radioactive levels in marine life.

The emergency power system at Millstone 1 consists of one diesel generator and one gas turbine generator. If normal power to the plant is lost, the gas turbine is the sole power source for the feedwater coolant injection (FWCI) system. The gas turbine generator failed to start or run for its entire mission 37 times. Many of these failures occurred when redundant power systems or systems redundant to the FWCI system were not operable.

Five excessive thermal transients in eight blowdowns were experienced resulting from failures of safety and relief valves. The cooldown rates during the transients ranged from 105°F/h to 450°F/h. The first of these events occurred in 1971. Between 1975 and 1981 the transients occurred at a rate of about one every two years. There were no further recurrences after 1981.

Ten instances of pipe cracks were reported. Cracks appeared in feedwater spargers, core spray piping, main steam line supports, and condenser nozzles. Pipe cracking found at Millstone is typical of the generic problems found in many BWRs.

A variety of problems caused twelve failures of the isolation condenser valves between 1970 and 1984. In seven of the twelve events, a supply valve either opened too wide or failed to open, which caused the

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isolation condenser system to fail. On one occasion a valve transferred open causing an isolation condenser system failure. On another occasion, a valve transferred open and initiated the isolation condenser system. Another event occurred because a return valve failed to close. Three isolation valve failures occurred two of which were due to limit switch problems.

There were eight occurrences of failure of main steam isolation valves (MSIVs). The predominant cause for MSIV failures involved a poor quality of control-air supplied to the pilot valves. This failure mechanism has the potential to affect more than one MSIV at a time. All MSIV related failures occurred prior to 1981.

There were two events involving set point drift in safety/relief valves. A total of six valves were affected. This is a generic problem for BWRs.

On two occasions in 1982 a loss of the stack gas monitor was experienced resulting from operator error. A design change was made to include both a timer and an alarm for the monitor to prevent recurrences of this problem. No events involving the stack gas monitor were reported after 1982.

Nine reports of finding higher than allowed levels of radioactive silver and cobalt in marine life were submitted during the period from 1981 through 1984. The majority of occurrences were in 1982 and in 1983. The utility concluded from calculations of the dose consequences that the doses were insignificant and that the reporting requirements are overly conservative.

Plant Visit

As part of the review effort the ISAP operations assessment team visited the plant. Valuable insights were gained from discussions with plant personnel and from a tour of the Millstone plant facilities. Plant personnel openly answered questions that arose from the review analysis. Visual inspections of the general plant conditions, the state of operating equipment and the areas where problems in operations had been experienced provided additional perspective to the team for their evaluations.

Conclusions

The findings of this review do not lead to any conclusion that there are continuing major challenges to plant safety inherent in the operations of Millstone 1. As evidenced by the record of the plants availability and capacity factors over the period of the review, and the relatively small number of significant reportable events, the operational record of Millstone 1 can be judged to be better than average.

Nevertheless, a number of problems are identified from the data. Significant recurring problems are evident in eight discrete areas. Examination of the data shows that the recurrence of two of these eight areas, failures in the stack gas monitor and high cooldown rates, has ceased. In one area involving reports of radioactivity levels in marine life that were higher than allowed, the problem was found to lie in overly conservative reporting requirements, and has been alleviated through technical specification changes. However, the other five problem areas remain as outstanding concerns. These five are:

1. Loss of emergency power supply capabilities,
2. Pipe cracks,
3. Isolation condenser valve failures,
4. MSIV failures, and
5. Safety/relief valve setpoint drift.

The data shows that the majority of the operating experience problems were confined to random events, reflecting much of the experience of other operating BWRs. No other significant problems are identified through trends or patterns in the data.

Operational review findings provide real indicators of importance which can be used in the evaluation and prioritization of regulatory topics which are to be applied to a particular plant. Accordingly, the results and conclusions from this operational experience review can be included as one of the tools for the resolution and prioritization of the Millstone 1 ISAP issues.

ABSTRACT

A review of the operating experience of the Millstone 1 nuclear power plant was performed for the Nuclear Regulatory Commission's Integrated Safety Assessment Program (ISAP) by the Nuclear Operations Analysis Center. The operating history of the plant from 1970 through 1984 was reviewed and analyzed. The findings of the review identified trends and symptoms in the operating data that can be used as tools in the resolution and prioritization of the Millstone 1 ISAP issues.

The review includes evaluation of data collected on plant availability and capacity factors, forced shutdowns, power reductions, reportable events (reportable occurrence, licensee event reports, etc.), and environmental considerations. The methodology used is also discussed. Data and information is presented in appendices.

It is concluded that operational problems in eight areas impacted upon the performance of Millstone 1: loss of emergency power supply, pipe cracking, isolation condenser valve failures, MSIV failures, SRV setpoint drift, excessive cooldown rates, stack gas monitor failures, and radioactivity levels in marine life. The last three areas appear to be resolved. However, the other five areas remain as outstanding issues.

1. INTRODUCTION

In the early 1980's the Nuclear Regulatory Commission (NRC) implemented a program of reviews of older operating commercial nuclear power plants. This program, called the Systematic Evaluation Program (SEP), grew out of a concern that some older plants were licensed under regulations that may have been less stringent than those in existence today. Specifically, SEP accomplished five objectives:

1. The program established documentation showing how, for each operating plant reviewed, the plant specific criteria compare with current criteria on significant safety issues, and provided a rationale for acceptable departures from these criteria.
2. The program provided the capability to make integrated and balanced decisions with respect to any required backfitting.
3. The program was structured for early identification and resolution of any significant deficiencies.
4. The program assessed the safety adequacy of the design and operation of currently licensed nuclear power plants.
5. The program used available resources efficiently and minimized requirements for additional resources by NRC or industry.

Through SEP, the NRC recognized a need to provide order and efficiency in the implementation and resolution of regulatory requirements for operating nuclear plants. The experience gained from SEP and the Interim Reliability Evaluation Program (IREP) enabled the NRC to develop a new and integrated approach called the Integrated Safety Assessment Program (ISAP). In early 1985, the NRC implemented a pilot program for the ISAP which will examine two volunteer plants — Millstone 1 and Haddam Neck.

The features of ISAP lie in the integration of many different programs currently applied to the management and regulation of operating nuclear plants. Through an integrated evaluation of these programs, ISAP will enable a balanced and cost effective approach to the management of regulatory requirements on a specific basis for individual operating plants. Evaluation tools for ISAP will typically include: (1) the deterministic reviews of all pending licensing actions and safety issues; (2) a plant specific Probabilistic Safety Analysis (PSA); and (3) an evaluation of plant operating experience.

In SEP it was found that plant Operating Experience Reviews contributed significant value to the program. These reviews compiled and evaluated data on availability/capacity factors, forced shutdowns and reportable occurrences. They provided additional perspective for the integrated assessment of the plant, and it was recognized that their contributions were equally as significant as those made by safety topic evaluations and risk analyses.

Thus, operating experience reviews are included as an integral part of the ISAP evaluation process and will be used to (1) confirm the

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adequacy of the data used in the plant specific PSA, and (2) highlight strengths and weaknesses in plant operation and maintenance which could be considered as factors for judging the adequacy of any proposed corrective actions to resolve an issue.

The NRC contracted with the Nuclear Operations Analysis Center, part of the Oak Ridge National Laboratory, to perform the operating experience reviews for ISAP. This report presents the results of an operating experience review for the Millstone 1 Nuclear Plant, and updates an earlier report published under the Systematic Evaluation Program, NUREG-0824, "Integrated Plant Safety Assessment, Systematic Evaluation Program - Millstone Nuclear Power Station Unit 1". The review includes evaluation of data collected on availability and capacity factors, forced shutdowns, forced power reductions, reportable events, environmental events, and radiological release events.

Section 2 of this report contains a brief description of the methodology employed in the review.

Section 3 discusses the results of the operating experience review. Section 3.1 describes the review of operational performance (availability and capacity factors), and environmental problems. Sections 3.2 and 3.3 describe the forced shutdowns (including power reductions) and reportable events, respectively. These two sections give yearly summaries as well as summaries by system, cause, and significance.

Section 4 presents findings and conclusions based on observed trends or patterns in the operating experience of Millstone 1.

Appendices A and B describe the coding of both forced shutdown and reportable events respectively. They contain detailed information about the events in tabular form.

2. TECHNICAL APPROACH

This report presents the findings of a review of the operating experience at Millstone 1. It updates an earlier operating experience review conducted for the Systematic Evaluation Program (SEP).[1] As a major difference from the SEP review, a goal of this report is to provide specific conclusions about the plant's actual operational performance which can be used in the overall assessment of the importance of regulatory issues applied to Millstone 1.

The objective of the review is to provide insights into the actual strengths and weaknesses of the design, operation and maintenance of the Millstone 1 plant. The results of the review will be used with other ISAP tasks, in an integrated approach to establish a manageable regulatory baseline. From this baseline a plant specific "living schedule" of plant modifications can be generated.

The evaluation of the operational history consisted of a four-step process: (1) compiling information on plant operating events, including forced shutdowns and reportable occurrences, (2) screening the events to determine their significance, using selected criteria and guidelines (3) evaluating and categorizing events to facilitate a search for trends or symptoms in operating characteristics, and (4) preparing findings based on any observed trends or patterns identified in the data.

Data was compiled on the following aspects of operation: availability and capacity factors, events of environmental importance including radioactivity releases, forced shutdown and power reduction events and reportable events.

The main focus in this evaluation is on forced shutdowns and power reductions, and on reportable events. Availability and capacity factors, and information about environmental events are used to establish an overall perspective on plant operations. Procedures that assured consistency in the review were applied to the screening and categorizing of the information about these events. After the screening and categorizing, a safety significance assessment of the events was made and the existence of any determinable trends or relationships was established.

2.1 Availability and Capacity Factors

Both reactor and unit availability factors have been compiled for all years of operation. Starting with 1974, the unit capacity factors, using the Design Electrical Rating (DER) in net megawatts (electric), and the Maximum Dependable Capacity (MDC) in net megawatts (electric), were compiled as well. Data on capacity factors was not available from earlier years.

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The two availability and two capacity factors are defined as follows:

1. Reactor Availability =

$$\frac{\text{hours reactor critical + reactor reserve shutdown hours}}{\text{period hours}} \times 100$$

2. Unit Availability =

$$\frac{\text{hours generator on line + unit reserve shutdown hours}}{\text{period hours}} \times 100$$

3. DER Unit Capacity $= \dfrac{\text{net electrical energy generated}}{\text{period hours} \times \text{DER net}} \times 100$

4. MDC Unit Capacity $= \dfrac{\text{net electrical energy generated}}{\text{period hours} \times \text{MDC net}} \times 100$

The reserve shutdown hours is the length of time the reactor is not critical (or the unit is shutdown for administrative or other similar reasons) when operation could have been continued. The period hours are the total number of hours in the period under consideration.

2.2 Environmental Events

Any significant or recurring environmental problems were summarized based on the review of forced shutdowns, power reductions, reportable events (environmental LERs), and other operating reports. Routine radioactivity releases were tabulated and those releases where established limits were exceeded were reviewed.

2.3 Forced Shutdowns and Power Reductions

Data on forced shutdown and power reduction events were collected and reviewed for each incident. Forced shutdowns generally result from equipment failures or human errors that present an abnormal challenge to the unit's operation. Power reductions in general are caused by some need for maintenance or operations upgrade which does not require a full shutdown. The power reductions and forced shutdowns are included in chronological sequence in Appendix A.

Each shutdown or power reduction was placed in one of two sets of significance categories. The shutdown and power reductions were first evaluated against criteria for Design Basis Events (DBEs) delineated in Chap. 15 of the *Standard Review Plan.*[2] If the shutdown or power reduction could not be categorized as a DBE initiator, then it was placed in

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one of the Nuclear Operations Analysis Center (NOAC) categories. The method of assigning significance to and the coding of events is described in detail in Appendix A.

2.4 Reportable Events

Information on operating events reported in licensee event reports (LERs) and LER predecessors [e.g., abnormal occurrence reports (AORs), unusual event reports, and reportable occurrences (ROs)] was reviewed. This information was retrieved from the NOAC operational data files. Any documents that contained LER-type information (such as equipment failures or abnormal events) were coded so that they could be reviewed in the same manner as an LER. Primarily, this involved various types of operating reports and general correspondence for the early 1970s. Other sources of information such as the *Nuclear Safety Journal*[3] and reports from the NRC Office for Analysis and Evaluation of Operational Data were also used.

Two sets of criteria, established in the SEP reviews, were used in determining the significance of reportable events. The first set address those events whose results include challenges to the safety protection features of the plant. These events are termed "safety significant", and satisfy one or more of the following criteria:

- Two or more failures occur in redundant systems during the same event
- Two or more failures due to a common cause occur during the same event
- Three or more failures occur during the same event
- Component failures occur that would have easily escaped detection by testing or examination
- An event proceeds in a way significantly different from what would be expected
- An event or operating condition occurs that is not enveloped by the plant design bases
- An event occurs that could have been a greater threat to plant safety with (1) different plant conditions, (2) the advent of another credible occurrence, or (3) a different progression of occurrences
- Administrative, procedural, or operational errors are committed that resulted from a fundamental misunderstanding of plant performance or safety requirements
- Other

The second set address events that have the potential to challenge the safety protection features of the plant. These events, which might require additional information or evaluation to determine their full implication, were termed "conditionally significant", and satisfy one or more of the following criteria:

- A single failure occurs in a nonredundant system
- Two apparently unrelated failures occur during the same event
- A problem results in an offsite radiation release or exposure to personnel
- A design or manufacturing deficiency is identified as the cause of a failure or potential failure
- A problem results in a long outage or major equipment damage
- An engineering safety feature actuation occurs during an event
- A particular occurrence is recognized as having a significant recurrence rate
- Other

The methods for assigning significance to and for the coding of events are described in detail in Appendix B.

2.5 Evaluation of Operating Experience

The operating history of the plant was evaluated based on a review that involved screening, compiling, and categorizing data. Judgments and conclusions were made regarding safety problems, operations, trends (recurring problems), or potential safety concerns. Events were analyzed to determine their safety significance from the information provided through the various operating reports and the review process. The Final Safety Analysis Report (FSAR) and conversations with plant personnel provided specific plant and equipment details where necessary.

3. MILLSTONE 1 OPERATING EXPERIENCE

The review and assessment of the Millstone 1 operating experience for ISAP addresses the time from initial criticality in 1970 through 1984. The period from initial criticality through 1981 was included in the SEP review. This report incorporates additional data for the period 1982 through 1984 and updates the observations and findings presented in NUREG-0824, "Integrated Plant Safety Assessment, Systematic Evaluation Program - Millstone Nuclear Power Station, Unit 1".

Millstone Unit 1 is a General Electric Boiling Water Reactor (BWR) of 652 MWe net capacity. The plant is owned by Northeast Nuclear Energy Company and is located in Waterford, Connecticut. Ebasco Services Incorporated was the Architect/Engineer and the Constructor. The condenser cooling method is once-through, and Long Island Sound is the source of condenser cooling water (Fig. 3.1). The Plant is subject to license DPR-21, issued October 7, 1970, pursuant to Docket No. 50-245. The date of initial reactor criticality was October 26, 1970, and commercial power generation began on December 28, 1970.

Data was compiled on the following aspects of operation: availability and capacity factors, events of environmental importance including radioactivity releases, forced shutdown and power reduction events and reportable events.

3.1 Operational Performance and Environmental Impact

3.1.1 Availability and capacity factors

Millstone 1 availability and capacity factor data is summarized in Table 3.1. Fig. 3.2 shows that the reactor availability from 1971 through 1984 stayed above 70% with the exception of two years, 1973 and 1981, when major outages were necessary for repairs. In 1973, the feedwater spargers had to be replaced which necessitated an outage lasting almost 90 days. In 1981, after a seven month refueling outage, turbine balancing problems forced a 57 day repair outage. During the 14 full years of operation, 1971 through 1984, the plant had a cumulative reactor availability of 78.1% and a cumulative plant availability of 73.6%. Capacity factors were not available prior to 1973. The cumulative MDC and DER capacity factors from 1973 through 1984 were 66.0% and 65.4%, respectively.

3.1.2 Events of environmental importance

3.1.2.1 Radioactivity release events. Table 3.2 summarizes eleven reportable events that resulted in radioactive releases or personnel overexposures. Six of the events involved radioactivity releases caused by mishandling in, or failures of, the waste disposal system. The remaining five involved inadvertent exposures of maintenance workers.

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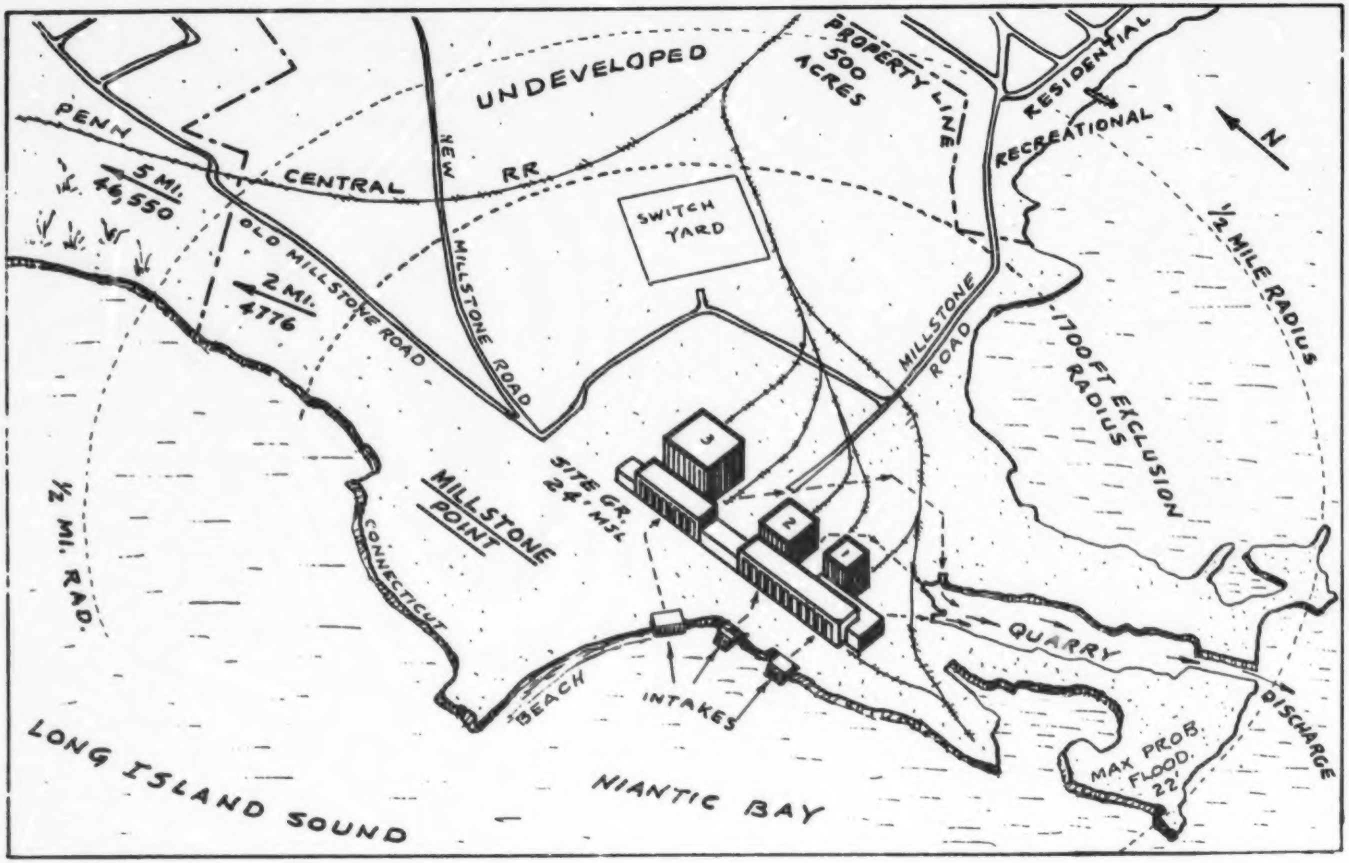
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RESIDENTIAL
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N
PENN CENTRAL RR
5 MI. 46,550
2 MI. 4776
NEW MILLSTONE ROAD
OLD MILLSTONE ROAD
SWITCH YARD
MILLSTONE ROAD
1700 FT EXCLUSION RADIUS
½ MILE RADIUS
½ MI. RAD.
SITE GR. 24' MSL
MILLSTONE POINT
3
2
1
CONNECTICUT
BEACH
INTAKES
QUARRY
DISCHARGE
MAX PROB. FLOOD. 22'
LONG ISLAND SOUND
NIANTIC BAY

Fig. 3.1 Millstone Nuclear Power Station Site[4]

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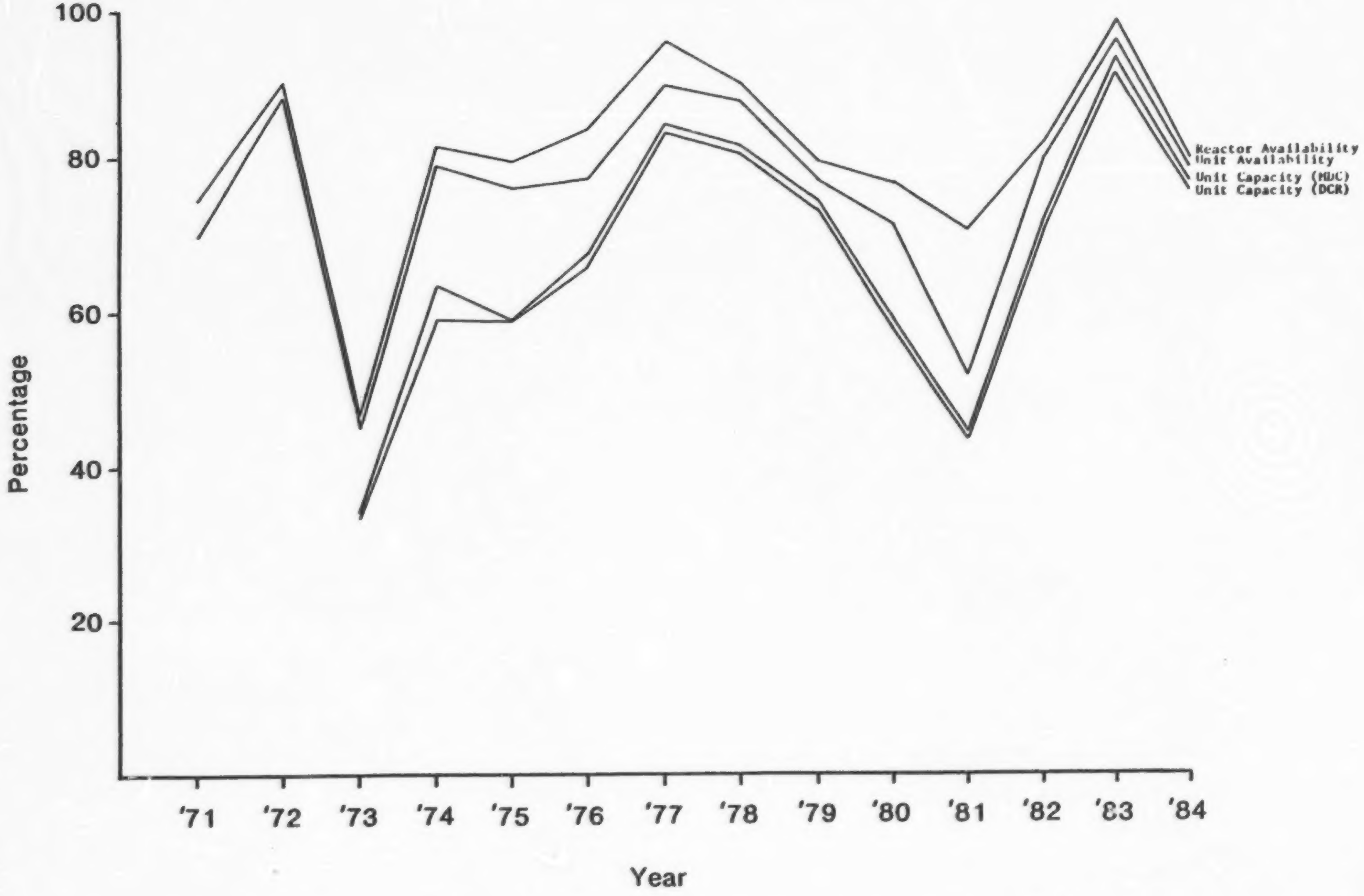

Fig. 3.2 Availability and capacity factors for Millstone 1

Table 3.1. Availability and capacity factors for Millstone 1

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Cumulative
Reactor availability	ND[a]	74.1	89.2	47.3	80.9	79.0	84.0	96.0	89.0	79.1	76.0	69.0	80.4	96.7	79.6	78.1
Unit availability	ND	69.3	88.1	45.5	79.1	75.6	76.1	89.6	87.6	77.3	69.0	51.6	79.9	95.6	78.8	73.6
Unit capacity (MDC)[b]	ND	ND	ND	33.8	63.1	68.4	66.1	84.1	81.3	73.7	59.0	44.0	71.2	93.5	75.2	66.0
Unit capacity (DER)[c]	ND	ND	ND	33.2	59.6	68.4	65.6	83.4	80.5	73.0	58.5	43.6	70.5	92.6	74.6	65.4

[a] ND = No data.

[b] MDC = maximum dependable capacity.

[c] DER = design electrical rating.

Table 3.2. Events of radioactivity releases or personnel exposures at Millstone 1

Number	Event date	Cause	Description
—	3/25/74	A	Three workers were overexposed due to poor ventilation in area
—	1974	A	Badge readings showed three men exceeded their dose limits
AO 75-5	3/27/75	E	Wiring error caused flow of contaminant into boiler system
AO 75-6	3/30/75	A	Inadvertent discharge of radioactive liquid to environment
—	9/75	H	Worker exposed to airborne activity. Did not have work permit
—	10/75	H	Two workers exposed to airborne activity. Exhaust trunk was not operating
—	11/76	B	Two unmonitored liquid release paths discovered
RO 76-17	4/23/76	B	Noble gas release rate exceeded limits
RO 77-40	12/13/77	D	Two hydrogen explosions caused excessive release out the stack
LER 81-02E	6/22/81	H	Unmonitored radioactive liquid waste released
LER 81-03E	8/13/81	H	Unmonitored release of liquid effluent

Human error was the cause of 10 of the 11 events. The eleventh event was a consequence of design features inherent in all BWRs. On December 13, 1977, two hydrogen explosions occurred in the off-gas system; the second explosion caused a small, uncontrolled release of radiation.

The first of the human error events occurred on March 25, 1974. Two workers were overexposed to Co-58 and Co-60 due to poor ventilation in a maintenance area. Badge readings taken during the fall 1974 refueling outage showed that three men had received doses in excess of their allowable limits. An overflow of a surge tank onto the boiler room floor resulted in the contamination of the shoes of a worker on March 27, 1975. In September, 1975, one worker ingested small amounts (<1500 nanocuries) of Co-60 and Mn-54. In October 1975, five workers received radiation doses in excess of allowable limits while performing maintenance on the feedwater spargers.

Table 3.3 lists the annual radioactive releases from the plant. Through the fifteen years of operating experience that was covered by this review, there were 17 reports of radioactivity in excess of regulatory limits occurring in plants and animals near the Millstone site. Most of these involved high levels of activity in the oysters in Niantic Bay. One report, however, revealed a high iodine activity in cow's milk samples taken from the area. This was not related to the plant but rather to fallout from the Chinese atomic bomb tests.

In 1981, Millstone began submitting reports of finding high levels of Ag-110 m, Co-58, and Co-60 in aquatic organisms. Ten reports between May 24, 1981 and May 16, 1984, detailed radioactivity levels that were higher than the technical specification reporting level. However, the actual level of activity was no higher than that found in previous years. The utility concluded from calculations of the dose consequences that the doses were insignificant and that the reporting requirements are overly conservative.

The existing Technical Specifications require "Anomalous Measurement Reports" when plant related activity is a factor of 10 times the control location (actually this turns out to be 10 times the statistical error in determining the background, since background levels are typically zero). Even when very low concentrations are detected in marine life, there may be "anomalous Measurement Reports" since background is measured with such a high degree of accuracy. In 1975 through 1976 there were 7 such reports. Since that time, the augmented liquid radwaste system has reduced the releases from Unit 1 to levels that are usually undetectable in marine life. Beginning in 1979 routine discharges and anticipated operational occurrences have resulted in one such report caused by the operation of Unit 1 and fifteen from Unit 2.

In all cases the releases were within the allowed discharge limits and the measured levels in the marine life indicate that the dose consequences are well below the 10CFR50, Appendix I limits. Therefore, the utilities' Radiological Effluent Technical Specifications (RETS) submittal has incorporated the suggested more realistic reporting criteria from the "model" RETS.

Table 3.3 Summary of radioactivity released from Millstone 1

Release (curies)	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Airborne:															
Total noble gases	4.1E+2	2.70E+5	7.26E+5	2.90E+4	9.12E+5	2.97E+6	5.07E+5	6.20E+5	5.60E+5	2.06E+4	1.19E+4	1.43E+4	8.33E+3	6.34E+3	2.81E+3
Total I-131	3.2E-10		1.24E+0	1.54E-1	3.18E+0	9.77E+0	2.19E+0	4.66E+0	3.19E+0	4.01E-1	2.14E-1	7.52E-2	9.92E-2	2.92E-2	2.05E-2
Total halogens	NA	3.94E+[illegible]	1.23E+0	1.54E-1	3.18E+0	6.29E+1	3.65E+1	6.10E+1	3.19E+0	4.01E-1	3.16E+0	1.05E+0	1.41E+0	5.69E-1	5.91E-1
Total particulates	NA	5.87E-2	8.75E-6	4.10E-2	8.77E-2	1.88E-1	1.49E-1	2.01E-1	1.36E+0	1.89E-1	1.13E-1	6.86E-2	1.10E-1	3.33E-2	4.10E-2
Total tritium	NA	3.21E+0	4.21E+0	1.69E+0	7.85E+0	1.72E+1	2.87E+1	6.52E+1	3.36E+1	5.30E+1	9.55E+1	9.47E+1	5.38E+1	7.59E+1	7.71E+1
Liquid:															
Total mixed products	NA	[illegible].97E+1	5.15E+1	3.34E+1	1.96E+2	1.99E+2	9.65E+0	5.27E-1	1.74E-1	2.09E-1	7.16E-1	3.96E-1	1.15E+0	8.08E-1	3.76E-2
Total tritium	NA	1.27E+1	2.09E+1	3.70E+0	2.41E+1	6.03E+1	2.01E+1	4.41E+0	2.22E+0	7.92E+0	2.73E+1	2.62E+0	6.21E+0	8.36E+0	8.58E+0
Total noble gases	NA	NA	0	0	0	1.11E+1	3.56E-1	3.67E-1	7.65E-1	7.00E-1	4.92E-1	4.00E-2	4.12E-1	2.43E-1	1.94E-2
Solid:															
Total	1.1E+0	2.61E+2	1.64E+3	1.51E+3	2.57E+3	2.58E+3	1.70E+3	3.03E+3	8.15E+4	1.16E+3	4.66E+3	1.83E+3	1.08E+3	6.82E+2	1.97E+3

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Furthermore, the measured levels are not related to any buildup in activity since the isotopes measured have a relatively short half-life and are related directly to the amount released during the calendar quarter.

3.1.2.2 Nonradiological events. The nonradiological environmental events included abnormal fish impingement on intake screens, pump fouling by aquatic organisms, and salt water induced equipment failures. Excessive fish impingement was reported on 18 occasions: 16 times in 1976, and 2 times in 1977. The unusually high numbers were attributed to an abnormal increase in fish population in 1976 and 1977. An emergency service water pump failed twice in 1982 as a result of marine life fouling the impellers.

The effects of a salty atmospheric environment have caused recurring problems in electrical systems at Millstone. Corrosion in the air start system for the gas turbine caused the turbine to fail four times between July 14, 1981, and February 7, 1983. The carbon steel piping in the air start system was replaced by stainless steel piping in 1983. On December 9, 1983, excessive salt deposits built up on the bushings of the reserve station service transformer (RSST). The RSST was declared inoperable until the salt deposits were removed.

3.2 Forced Reactor Shutdowns and Power Reductions

3.2.1 Review of reactor shutdowns and power reductions

A total of 152 forced reactor shutdowns and 50 power reductions occurred at Millstone 1 during the operating period from plant startup in 1970 through 1984. These events were categorized and analyzed in this review.

Table A.1 "Forced shutdowns and power reductions for Millstone 1," in Appendix A provides a comprehensive summary of the forced shutdown and power reduction events at Millstone 1. For those forced shutdowns and power reductions which were reportable events, more detailed descriptions are included in Sect. 3.3.

Tables 3.4 and 3.5 summarize the forced shutdowns and power reductions respectively. The causes of these events (Item I.3 in Table 3.4 and Item I.2 in Table 3.5) are dominated at Millstone 1 by equipment failures. Only six shutdowns attributable to operator errors were reported, and no power reductions were attributed to operator error.

3.2.2. Yearly summaries of forced shutdowns and power reductions.

Figures 3.3 and 3.4 show the annual rate of forced shutdowns and power reductions for the years 1970 through 1984. A brief discussion of the events occurring in each of those years follows:

Table 3.4. Forced shutdown summary for Millstone 1

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Totals
I. Forced shutdowns																
1. Total number	8	42	8	20	7	11	8	14	6	7	1	9	3	7	1	152
2. Total hours down	102	1336	585	2892	91	976	624	738	197	424	13	1641	99	395	42	10155
3. Cause[a]																
A. Equipment failure		37 (1209)	8 (585)	16 (2594)	7 (91)	10 (545)	8 (624)	14 (738)	5 (97)	7 (424)	1 (13)	7 (1536)	1 (30)	4 (199)		122 (8534)
B. Maintenance or testing	8 (102)	3 (121)				1 (431)			1 (100)			1 (55)			1 (42)	15 (851)
D. Regulatory restriction				1 (236)										1 (130)		2 (366)
E. Operator training/license exam																
F. Administrative																
G. Operational error		2 (8)		3 (62)								1 (52)	1 (18)			7 (140)
H. Other													1 (53)	2 (65)		3 (118)
4. Shutdown method																
A. Manual	3	11	4	12	2	7	5	2	2	2		1		3	1	55
B. Manual scram						1		4		1		2	1			9
C. Automatic scram	5	31	4	8	5	3	2	8	3	3	1	4	2	4		83
D. Other							1		1	1		2				5
II. Total number of DBE related shutdowns (these are included in totals of Part I)	4 (53)	26 (858)	4 (218)	3 (151)	6 (23)	0 (0)	0 (0)	2 (65)	3 (30)	3 (85)	1 (13)	4 (1636)	0 (0)	2 (45)	0 (0)	36 (2953)
1. Reactor vessels (CA)				6												6
2. Coolant recirculation system (CB)		2		4	1			1				1				9
3. Main steam systems and controls (CC)	1	8	3	3	2	5		1	2	1	1			1	1	29
4. Main steam isolation systems (CD)	1			1				1		1						4
5. Reactor core isolation cooling system (CE)	1	1		1			2									5
6. Reactor coolant cleanup systems (CG)								1		1						2
7. Feedwater system (CH)		1	1	3	2			1		1		2	1			12
8. Offsite power systems (EA)	1															1
9. AC onsite power systems (EB)						3	2									5
10. Onsite power systems (ED)									1							1
11. Emergency generator (EE)														1		1
12. Emergency lighting systems (EF)				1												1
13. Turbine generator and controls (HA)	2	20	3		1		1	1	1	1		3	1	2		36
14. Main steam supply system (HB)								5	1							6
15. Main condenser systems (HC)	1	2										1	1		1	6
16. Turbine bypass systems (HE)	1															1
17. Circulating water systems (HF)		2														2
18. Condensate and feedwater systems (HH)		1														1
19. Steam generator blowdown systems (HI)		1														1
20. Reactor trip systems (IA)		1						1	1			3				6
21. Instrumentation not required for safety (IE)														1		1
22. Instrumentation (IP)														1		1
23. Gaseous radwaste management system (MB)								1								1
24. Compressed air systems (PA)								1		1						2
25. Reactivity controls systems (RB)				2												2
26. Reactor core (RC)						1										1
27. Reactor containment systems (SA)		1	1		1									1		6
28. Emergency core cooling system (SF)										1						1
29. Low pressure safety injection system (SF-B)						1										1
30. Core spray system (SF-D)		2														2
31. Station service water systems (WA)						1										1

[a] Number of hours associated with cause of shutdown is in parentheses.

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Table 3.5 Power reduction summary for Millstone 1

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Totals
I. Power reductions																
1. Total number				1	6	3	1	3	10	3	1	3	7	7	5	50
2. Cause																
A. Equipment failure				1	6	2		1	10		1	2				23
B. Maintenance or testing						1		2		3		1	7	7	5	26
H. Other							1									1
3. System involved																
A. Turbine-generator (HA)					3			1								4
B. Main condenser (HC)				1	1			2	10	3		1	5	7	2	32
C. Reactor (RB)							1									1
D. Reactor (RC)						1							1		1	3
E. Electric power (EB)					1	1										2
F. Reactor coolant (CC)					1	1							1			3
G. Reactor coolant (CD)											1					1
H. Other instruments required for safety (IE)												1				1
I. Station service water (WA)												1				1
4. Total number of DBEs related power reductions (included in totals of Part 1)					3											3

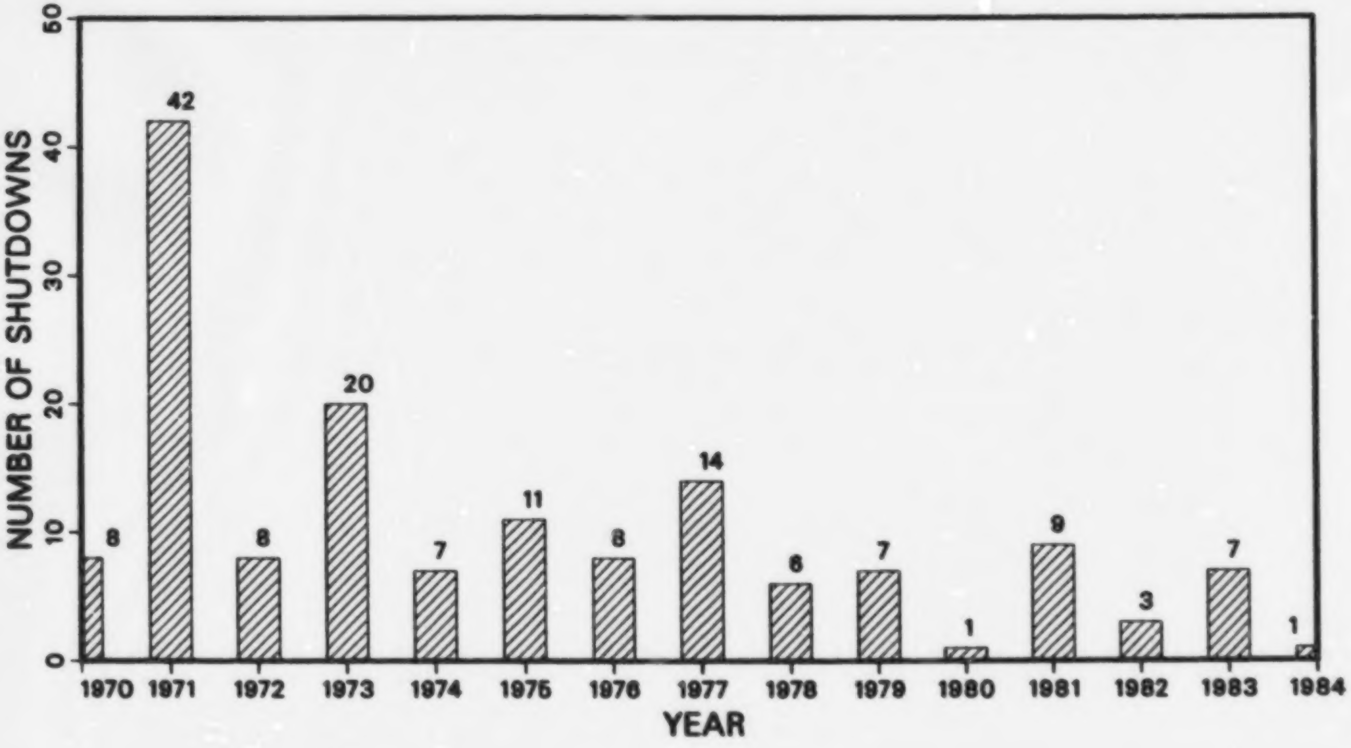

Fig. 3.3 Number of shutdowns per year at Millstone 1

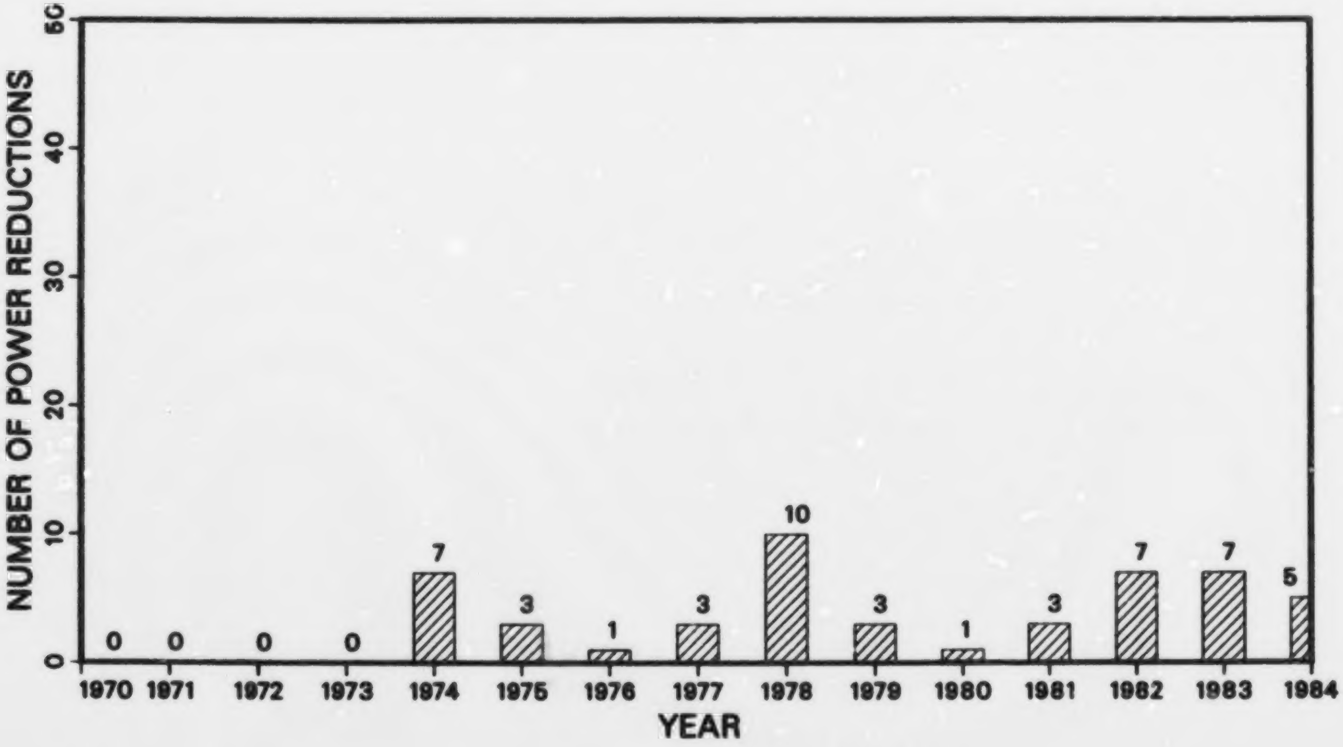

Fig. 3.4 Number of power reductions per year at Millstone 1

1970

The Millstone 1 BWR went critical on October 26, 1970. Eight forced shutdowns occurred during this year, seven of which were during startup testing. These seven were split about evenly between instrumentation malfunctions and faulty equipment installations. Maintenance and testing were the causes for all seven forced outages. The reactor coolant system was involved three times, and the steam and power systems were involved three times.

One shutdown was due to a cracked seal weld on the main condenser. Oscillation of a pressure control torque tube tore a bypass valve linkage away from its support, necessitating a shutdown.

A problem, recurring in later periods, first surfaced during this report period. The problem involved a moisture separator drain tank level indicator which indicated high, subsequently tripping the turbine and resulting in a reactor shutdown.

1971

During 1971 the reactor experienced 42 forced shutdowns, the most occurrences in a single year during the 15 years of operation covered by this review (Fig. 3.3). These shutdowns were attributed primarily to equipment failures (37 times). Three of the forced shutdowns were caused by maintenance and testing; 2 were for operator error.

The longest forced shutdown occurred on October 10, when the unit was down for 10 days to repair a turbine control valve. The next longest forced shutdown occurred on August 30, and lasted for 7 days. The traveling screens of the circulating water system became clogged with sea-weed causing the loss of the main condenser vacuum and a reactor scram.

At the beginning of 1971, only two months after the initial criticality, a high level indication in the moisture separator drain tank caused a steam turbine trip. This event recurred 11 more times during the year. These high level indications were attributed to broken baffle plate welds and to level control instrumentation malfunctions.

Another recurring event during this year first occurred on March 23. A steam turbine control valve malfunctioned necessitating a 2 day shutdown for valve testing. Six additional forced shutdowns occurred due to the malfunctioning of this valve.

There were six shutdowns due to miscellaneous instrumentation malfunctions. During two shutdowns, Millstone 1 repaired leaks in the main steam line.

1972

The number of forced outages dropped to 8 in 1972 (Fig. 3.3), with no reported power reductions. The total forced outage time was only 585 h, the fourth lowest in Millstone 1's history.

Two forced shutdowns in February lasted for a total of 12 days. These were due to improper responses from the main steam line venturi differential pressure transmitters. The sensing tubes were replaced. On March 12, a reactor scram occurred during plant heatup when a reactor feedwater pump was started when the water level in the reactor vessel reached the 10-in. level indication. The collapse of voids from the cold feedwater caused the level to decrease further and a low level scram resulted.

During the refueling outage which commenced September 1, the leaking tubes in the main condenser were plugged and all incore power range detectors were replaced.

1973

This year saw the second most forced shutdowns in Millstone 1's operating history: 20 forced shutdowns for 2892 h total (Table 3.4). Sixteen of these shutdowns were attributed to equipment failures. The longest forced shutdown occurred on April 18, and lasted for 89 days. At that time, all of the feedwater spargers were replaced because of cracks.

There was one forced shutdown of 10 days at the direction of the Atomic Energy Commission (AEC) to examine for possible inverted control rod internals. The General Electric Company had provided notice that some of the boron carbide poison pins were inverted during the blade fabrication process of some control rods. Some of these defective rods might have been installed in the Millstone core. In this inverted configuration, it was conceivable that axial downward shifting of the boron carbide powder could occur, and that this shifting could result in a change in the reactor core shutdown margin. A series of shutdown tests subsequently indicated nothing amiss.

Four of the shutdowns were due to instrumentation malfunctions, and four were due to lube oil pressure alarms on the reactor recirculating pump motor.

1974

This year saw a significant reduction in forced downtime in Millstone 1's operation: seven forced shutdowns for 91 h total (Table 3.4). In addition, there were seven power reductions that were attributed to equipment failures. Sea water leakage in the main condenser was detected necessitating two power reductions to plug tubes.

Recurrence of the problem of turbine trips, attributed to high level indications in the moisture separator drain tank, accounted for three more power reductions.

A refueling outage commenced on September 1, during which time the feedwater spargers were replaced for the third time as a result of excessive vibration at reactor power levels greater than 80%.

1975

This year Millstone 1 suffered the third worst level of forced downtime in its history. Of a total of 976 h forced out of service (11 forced shutdowns), 56% (547 hours) were caused by a transformer failure. On September 12, a combustible gas mixture was detected in the transformer, and a shutdown was made to change-out the transformer. Refueling was completed during this outage.

On March 3, a blown valve stuffing box on the low pressure cooling injection system occurred, resulting in water blowing from the identified leakage sump into the unidentified leakage sump.

1976

During this year there were eight forced shutdowns. On August 10, high winds deposited salt spray on the main transformer insulators causing arching between insulators. This caused the generator to trip. During the resulting outage, the gas turbine speed control became inoperable necessitating the replacement of the electronic governor.

On July 16, a shutdown was necessary to repair the motor operator of the isolation condenser isolation valve. On December 17, this same valve malfunctioned resulting in a shutdown to clean it.

1977

In 1977, there were 14 forced shutdowns due to equipment failure for a total of 738 h. On June 14, a mechanical pressure regulator malfunctioned, tripping the steam turbine and causing a 5-day shutdown. In August, main condenser tube failures occurred again at Millstone 1. Several power reductions were made to plug the leaking tubes. On December 13, 1977, the first of two hydrogen explosions occurred in the off-gas system. Since the explosion was confined within a massive underground pipe, damage was minor and the reactor was able to continue operating while the damage was being repaired. However, since the second explosion was not confined, considerable damage in a two-level room at the base of the stack and to the plant stack itself occurred. The reactor was manually tripped.

1978

This year there were only six forced shutdowns for a total of 197 h. Starting in June, main condenser tubes began leaking and troubled Millstone 1 for the rest of the year. Ten power reductions took place in order to plug leaking tubes. Again, level control malfunctions occurred in the moisture separator drain tank.

1979

Seven forced shutdowns occurred this year for a total of 424 h. The most significant event occurred on January 6 and lasted for 11 days. Stress corrosion cracking in the clean-up return line necessitated replacement of this piping. Power was reduced three times to plug leaking tubes in the main condenser. On July 2, a shutdown, due to low water level from the feedwater regulator valve lockup, resulted from the loss of both plant air compressors.

1980

Only one forced shutdown was reported in 1980. A water hammer was experienced in the isolation condenser piping on December 19, 1979. The isolation condenser was placed out of service on January 5. Power was reduced and restricted to 40% for 27 d during the modifications made to the isolation condenser piping supports.

1981

At the beginning of 1981, Millstone 1 was continuing a refueling/maintenance outage which had begun October 4, 1980. The outage continued 2598 h from January 1 until the middle of April. There were nine forced shutdowns totaling 1641 h of downtime and three forced power reductions.

On April 21, the turbine experienced high vibration and was manually tripped. The reactor scrammed due to high main condenser conductivity. Balancing problems caused the turbine outage to last 1372 h.

On July 12, a feedwater regulator valve failed to close. On August 8, recirculation pump "A" tripped while recirculation pump "B" was offline. The unit was manually scrammed.

On August 10, a scram occurred during a surveillance test when an operator failed to reset a scrammed channel before testing the other channel. On September 14, a power surge to the ATWS system caused the scram air header to depressurize.

1982

In 1982, there were three forced shutdowns, which resulted in a total of 99 h of outage. On February 12 the "A" train feedwater regulator valve cycled open and then closed and this generated an automatic scram. On April 13 a reactor recirculation pump trip was automatically initiated by Division I of the ATWS system. The trip resulted when a 125 volt DC circuit breaker, supplying the Division I panel, was switched off. The breaker was switched off to enable the varying of the battery charger output voltage, without affecting the associated ATWS channel, in an attempt to locate a ground in the 125 volt DC power system. On July 31, the generator out-of-step relay, located in the switchyard, malfunctioned and tripped open the switchyard breakers. This caused a full-load rejection followed by an ATWS Division I scram.

Seven power reductions were required for maintenance activities, five of which involved leaking main condenser tubes.

1983

There were seven forced shutdowns in 1983 accounting for 395 h of outage. In addition, seven power reductions were required for maintenance.

On January 24, an automatic scram occurred when a steam tunnel high-temperature alarm which was caused by moisture intrusion into the switch, resulted in a ground short in the switch. On March 24, while effecting an orderly shutdown to identify and repair drywell leakage, an addition of feedwater at too rapid a rate caused a level transient and the reactor was scrammed. In June the gas turbine became inoperable and the reactor was shut down. In August when the instrument air compressor tripped, a scram occurred on low air pressure. The reactor was shut down in November to repair the "A" recirculation pump seal because of leakage.

In March, a high moisture separator level and in June, a high reactor water level both caused reactor trips.

1984

During 1984 there was only one forced outage. On August 8, the plant was shutdown to allow entry into the drywell to find and repair a leak in the recirculation system riser instrument valve. There were five power reductions during the year, two of which were required to find and repair leaking main condenser tubes. On December 5, power was reduced to repair a sticking "B" train feedwater regulator valve.

3.2.3 Systems involved in forced shutdowns and power reductions

Thirty-one different systems were involved in forced shutdown and power reduction events; the turbine generator and control system and the main steam control system together account for 45% of these events. Excluding these two systems, the average number of forced shutdowns per system was three during the operating period of the plant through 1984.

There were 36 forced shutdowns involving the turbine-generator and its associated controls with 20 of these occurring during 1971. In 1971, 14 events involved the high moisture separator drain tank level indicators, 4 involved turbine control valves, and 2 were caused by the loss of an offsite power line due to lightning. In 1979, a loss of main generator excitation was experienced.

There were 27 forced shutdowns involving the main steam system and its controls. Almost one-third of these occurred in 1971. On 11/11/70, 11/21/70, 11/4/74, and 7/12/77 inadvertent closure of MSIVs occurred. On 3/2/71, 10/21/71, 9/20/73, 5/20/77, 11/29/77, and 2/26/79, pressure relief or safety valves either failed to close or opened prematurely.

There were seven forced shutdowns involving condensate and feedwater systems. On 5/25/71 and 12/16/74, feedwater control valve closures prevented the flow of feedwater. On 3/12/72, a void collapse occurred from an increase in cold feedwater flow. On 3/6/73, a condensate booster pump was not started in time, resulting in a low water level. On 4/18/73, the feedwater sparger was replaced requiring a shutdown lasting 90 days. On 8/10/73, high reactor water level was experienced due to the starting of a feedwater pump.

Of the 49 power reductions, 65% involved the main condenser system. Three of the power reductions were classified as DBE initiators.

3.2.4 Causes of forced reactor shutdowns and forced power reductions

Of the 152 forced shutdowns, 80% were caused by equipment failures for a total of 8533 h. Maintenance and testing accounted for 10% of the shutdowns, for a total 844 h. There were only seven events due to operational errors for a total of 140 h.

Of the 50 power reductions, 47% were caused by equipment failures and 53% were caused by maintenance and testing errors.

3.2.5 Non-DBE shutdowns

Table 3.6 summarizes the NOAC categories assigned to non-DBE shutdowns. Only the major NOAC categories are listed in this table. Equipment failures accounted for 67% of the events with no apparent decline during the first nine years of operation. Instrumentation and control problems accounted for 20% of the events, and these recurred throughout the period addressed by the operational review.

Table 3.6 Non-DBE shutdowns and power reductions

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Total
Equipment failure N1.0		1														1
Failure on demand N1.1	1	1					1						1		1	5
End of design life N1.1.4	2	10	3	11	6	12	7	9	11	6		2	4	9	4	96
Instrumentation and controls N2.0																
Hardware failure N2.1		1		3		1		2					2	1		10
Spurious signal N2.4		1		2				4	1	1						9
Non-DBE coolant loss (leaks) N3.0																
Primary system N3.1		2	1									1	1	2	1	8
Maintenance error N5.0																
Failure to repair N5.1						1										1
Operator error N6.0																
Incorrect action N6.1		2										1				3
Inadvertent action N6.3				1									1			2
Regulatory restriction N8.0																
Backfit/reanalysis N8.3				1												1
External events N9.0																
Environment induced N9.2							1									1
Environmental operating N10.0				1									1			2
	3	18	4	19	6	14	9	15	12	7	0	4	10	12	6	139

3.2.6 DBE initiating events

Of the 202 forced shutdowns and power reductions accumulated at Millstone 1, 59 are classified as DBE initiating events as shown in Table 3.7. However, none of these events actually initiated a sequence leading to any significant economic loss or safety hazard to the plant or to the environs. The trend in the total number of DBEs per year showed no correlation with any other trends, such as plant performance as measured by total number of shutdowns per year, or total downtime per item (Table 3.4). Each specific type of DBE is discussed below.

3.2.6.1 DBE Sect. 1 events — increases in heat removal. Seven events (12%) are categorized into this section. Those seven events are subcategorized as described below:

D1.1 — Feedwater system malfunctions resulting in a decrease in feedwater flow. On May 25, 1971, a low water level reactor scram occurred when the valve positioner on one of the feedwater regulation valves failed. This caused the partial closure of a feedwater control valve resulting in insufficient flow and a reactor scram on a low reactor water level.

D1.2 — Feedwater system malfunctions that result in an increase in feedwater flow. On March 12, 1972, a reactor scram occurred during plant heatup when a reactor feedwater pump was started at the 10-in. level indication in the reactor vessel. The void collapse from the injection of cold feedwater into the reactor vessel resulted in a level decrease and low level scram.

On August 10, 1973, a malfunction of a reactor water level transmitter resulted in a false low level signal to the feedwater control valve circuit. This resulted in increased flow followed by reactor high water level, resulting in a scram. Later the same day, a scram occurred due to a high water level which was the result of an operator starting a feedwater pump with the feedwater regulating valves in the full open position.

On June 7, 1983, the reactor scrammed on a high reactor water level trip.

D1.3 — Steam pressure regulator malfunction or failure that results in an increasing steam flow. There were three events of this kind, all attributed to instrumentation malfunctions. On November 19, 1970, installation of scrubbers near the main steam line high flow ΔP switches was in progress. While wiring an isolation switch, a momentary high flow signal was initiated, and the main steam lines isolated generating the reactor scram.

On December 5, 1970, while shifting to Electric Pressure Regulator (EPR) pressure control, EPR oscillated giving bypass valve swings and pressure and reactor vessel water level swings. The result was a low level signal yielding a reactor scram. On September 21, 1973, a fault in the EPR controls opened the turbine bypass valves, causing reactor pressure to drop and the plant to scram.

Table 3.7 DBE initiating events at Millstone 1

	DBE category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Totals
Feedwater system mal functions that result in a decrease in feed water temperature	D-1.1		1														1
Feedwater system malfunctions that result an increase in feedwater flow	D-1.2			1	1										1		3
Steam pressure regulator malfunction or failure that results in increasing steam flow	D-1.3	2			1												3
Steam pressure regulator malfunction or failure that results in decreasing steam flow	D-2.1	1	1									1					3
Loss of external electric load	D-2.2		2														2
Turbine trip (stop valve closure)	D-2.3	1	18	3		4				3	2		2		1		34
Inadvertent closure of main steam isolation valves	D-2.4					1			1								2
Loss of condenser vacuum	D-2.5		1														1
Loss of normal feedwater flow	D-2.7				1	1							1				3
Single or multiple reactor recirculation pump trips	D-3.1												1				1
Inadvertent opening of a pressurizer safety or relief valve in a PWR or a safety or relief valve in a BWR	D-6.1		1						1		1						3
TOTAL		4	24	4	3	6	0	0	2	3	3	1	4	0	2	0	56

3.2.6.2 DBE Sect. 2 Events — decrease in heat removal. Forty-five events are categorized into this section. Thirty-four of them (75%) were caused by turbine trips. Three of these were associated with steam pressure regulator malfunctions, two with losses of external electric loads, two with inadvertent closures of main steam isolation valves, three with failures in the feedwater system, and one with loss of condenser vacuum. The events in this section are subcategorized as discussed below:

D2.1 — Steam pressure regulator malfunction or failure that results in decreasing steam flow. On November 21, 1970, vibration of the reactor mode switch resulted in a main steam isolation. On January 19, 1971, the turbine control valve closed, causing the reactor to shut down. On June 25, 1980, an electric pressure regulator malfunction induced an APRM scram.

D2.2 — Loss of external load. On June 24, 1971, and again on June 25, 1971, there were turbine full load rejects due to lightning strikes which caused loss of the 345 kv line.

D2.3 — Turbine trip (stop valve closure). Twenty-two of the 34 turbine trip events were attributable to malfunctions of the moisture separator drain tank level control. This type of event first occurred on December 30, 1970, and continued to recur irregularly 14 times in 1971, 3 times in 1974, 3 times in 1978, and one time in 1983.

On five occasions turbine control valve malfunctions occurred: 5/27/71, 9/29/71, 10/3/71, 10/10/71, 2/4/72. Each time this caused a turbine trip.

The remaining seven DBE's were isolated failures.

D2.4 — Inadvertent closure of main steam isolation valves. The two events in this category, occurring on 11/4/74 and 4/7/77, were attributed to mechanical failures in main steam valve actuators.

D2.5 — Loss of condenser vacuum. While this classification addresses the complete loss of condenser vacuum, an event which occurred on August 30, 1971 involving a low condenser vacuum is included in this subcategory.

D2.7 — Loss of normal feedwater flow. Of the three events in this category, one, occurring on March 6, 1973, was attributed to operator error for failing to start a condensate booster pump in time. The other event, on December 16, 1974, occurred as a result of a broken stem on the feedwater control valve. In the third event, a feedwater regulating valve transferred closed on July 12, 1981.

3.2.6.3 DBE Sect. 3 Events — decrease in reactor recirculation flow rate. The sole shutdown which resulted from a decrease in reactor recirculation flow occurred in 1981. On August 8, 1981, the "A" reactor recirculation pump tripped on generator overload. The "B" reactor recirculation pump was off-line at the time and the unit was manually scrammed.

3.2.6.4 DBE Sect. 6 — decrease in reactor coolant inventory. Three shutdowns were due to a decrease in reactor coolant inventory. On March 2, 1971, a main steam safety valve started leaking and blowing steam. On November 29, 1977, the automatic pressure relief valve lifted prematurely. On February 26, 1979, a safety relief valve lifted prematurely and failed to reseat.

3.2.7 Trends and Safety Implications of Shutdowns and Power Reductions

One recurring problem associated with forced outage and power reductions was due to inadvertent or premature opening of pressure relief or safety valves or their failure to close or seat. On 10/22/71, a relief valve failed to close completely. On 9/20/73, a relief valve was leaking. On 5/20/75, a relief valve failed to close completely. On 11/29/77, a relief valve opened prematurely. On 2/26/79, a relief valve lifted prematurely and failed to seat. On 3/21/71, a relief valve was found blowing steam.

3.3 Reportable Events

This study reviewed 404 reportable events that occurred at Millstone 1. Information reviewed included telegrams, letters, abnormal occurrences (AOs), reportable occurrences (ROs), and licensee event reports (LERs) that were filed by the utility when a technical specification was violated. The information contained in the reportable events was coded as discussed in Sect. 2.4. Data tables, arranged by year, are presented in Appendix B.

3.3.1 Review of Reportable Events from 1970 through 1984

Figure 3.5 illustrates the number of reportable events filed by year by Millstone 1. There is no discernible trend in the number of reports submitted on a yearly basis. The following sections present a summary for each year of operating experience at Millstone 1.

1970

The plant went critical on October 26, 1970. Ten reportable events were experienced during the year. Although none of the events were deemed significant to safety, two events are conditionally significant.

Eight of the reportable events that occurred during the first two months of operation in 1970 resulted from human error.

Human errors consist of design errors (4 events), installation errors (3 events), and operator and maintenance errors (1 event). Three

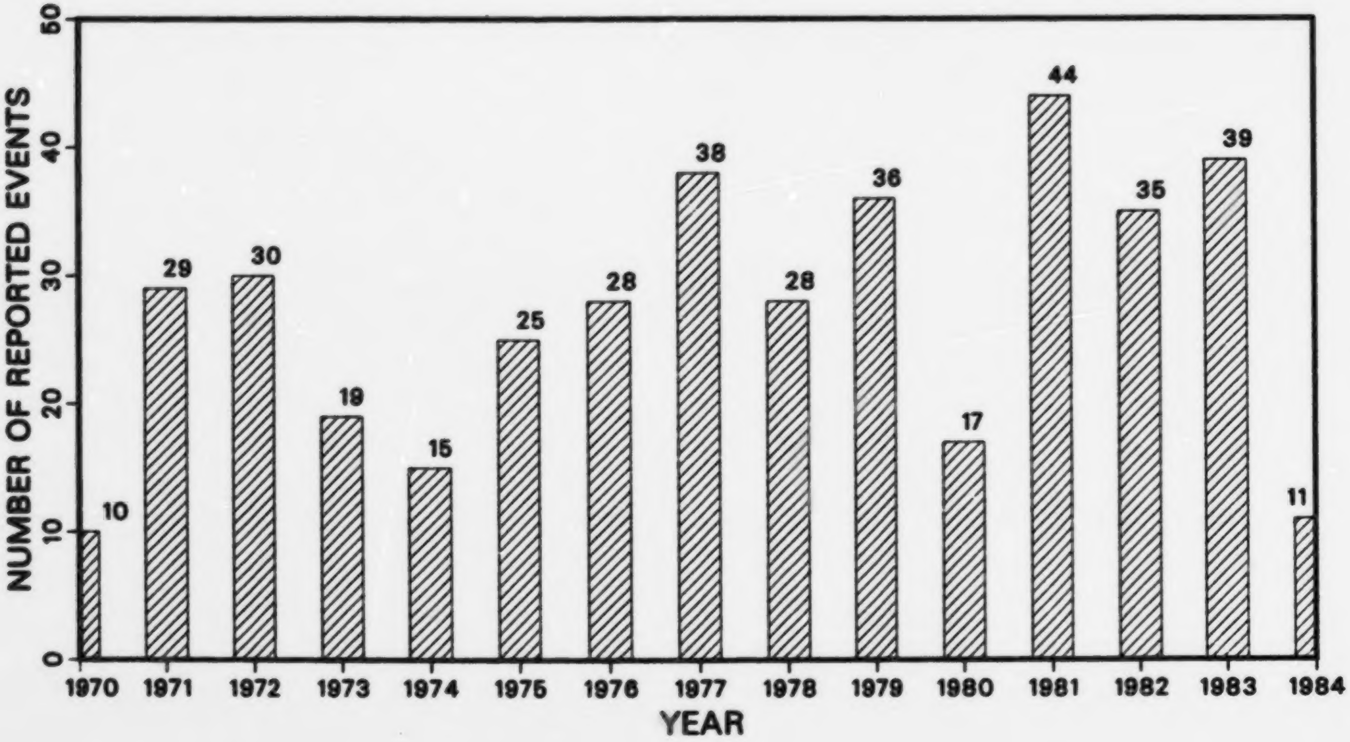

Fig. 3.5 Number of reportable events per year at Millstone 1

of the design errors consisted of inadequate pipe support of the main steam lines (RO-70-6), inadequate lubrication oil pump speed (RO-70-4), and an inappropriate wiring change that resulted in a loss of full rod control (RO-70-7). The fourth error caused the isolation condenser to isolate (RO-70-5) when a high-pressure signal initiated the operation of the isolation condenser. The resulting high condensate flow caused the isolation condenser to isolate. A restart of the system was unsuccessful and the pressure transient was brought under control through the use of relief valves.

Three reportable events resulted from installation errors. Installation errors included faulty welds in the main condenser (AO-70-8), failure of an MSIV due to missing parts (RO-70-6), and a vent line on the lube oil pump discharge line not being reinstalled (AO-70-10). Both events that are identified as RO-70-6 are conditionally significant to safety.

1971

Millstone 1 began commercial power generation in March 1971 and experienced 29 reportable events during the year. Two of these events are significant to safety and three are conditionally significant to safety.

The first significant event occurred on January 19, 1971, when the entire low pressure ECCS was rendered inoperable during a test (AO-71-1). The core spray injection valve failed to close and two LPCI valves failed to open. A turbine control valve unexpectedly closed causing the other three control valves to open further. Severe pressure oscillations caused reactor power oscillations of 8%. As soon as pressure control was changed from the mechanical pressure regulator to the electrical pressure regulator, the oscillations stopped.

The second significant event occurred on October 10, and involved a failure of the steam turbine bypass valve. This event resulted in a reactor blowdown. The defective valve was replaced.

Two of the three conditionally significant events involved the gasturbine generator (AO-71-12, AO-71-25). The remaining event occurred when a service water heat exchanger leak caused flooding of the DC motor control center (AO-71-09).

1972

The number of reported events increased to 30 in 1972. Human errors again contributed to a large number of the events that were reported. Maintenance errors (7 events), design errors (3 events), and installation errors (2 events) all contributed. The systems involved in the most events were the Main Steam System (6 events) and the Isolation Condenser system (5 events). No significant events occurred during the year, however four conditionally significant events occurred.

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Two of the conditionally significant events involved failures of multiple components (AO-72-17 and AO-72-18). In each case, the components involved were found to be out-of-calibration and were subsequently recalibrated.

The third conditionally significant event involved salt water intrusion in the main condenser (AO-72-22). Loss of the main condenser is not critical for plant safety, but the presence of chlorides in the system caused damage to other components in the reactor coolant system. Some of the resulting failures were not discovered until 1976 when 116 of the 120 local power range monitors (in-core) failed due to stress corrosion brought about by the excessive chloride content in the reactor water. Problems also arose from cracking of feedwater spargers in 1972 (AO-72-26).

The fourth conditionally significant event occurred on August 25. The plant experienced a loss of power to the shutdown transformers when a plane crashed into the 27.6 kv power line. The line was only 500 ft from the switchyard. The plant was operating at 82% power and did not reduce power after the crash.

1973

Nineteen reportable events occurred in 1975. Most of the events involved the feedwater control system (4 events) or the reactivity control system (4 events). One event is significant to safety and one event is conditionally significant.

Several control rod system problems surfaced in 1973. The event that is significant to safety involved degradation of the control rod drive accumulators due to flaking of plating into the hydraulic system. Six of the 143 accumulators had sufficient flaking to impair the operation of the control rod drive mechanism. These six were replaced and the hydraulic system was flushed. A program for monitoring accumulator conditions was initiated to prevent recurrence of the incident.

On April 5, pressure adjustments were being made as reactor power increased (AO-73-4). The pressure momentarily reached 1042 psig initiating the isolation condenser. The position switches were incorrectly set causing the inboard condensate return valve to open too wide. The resulting high flow condition automatically isolated the condenser. Due to the frequency of the isolation condenser valve failures, this event was classified as conditionally significant.

1974

The third smallest number of reportable events occurred in 1974 (15 events). None of the reportable events is considered to be significant or conditionally significant to safety. Most of the reportable events involved the reactor coolant system (8 events).

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Over one-half of the events involved a human error (9 events). Design errors and maintenance errors each accounted for four events. Two of the maintenance errors caused Main Steam Isolation Valve (MSIV) failures. The failures appear to be due to the poor quality of air provided to the pilot valves since the air slide valves stuck on both occasions. This failure mode is important in that it can cause more than one MSIV to fail at the same time. This would lead to plant conditions not considered in the plant's safety analysis.

1975

Twenty-five reportable events occurred in 1975. Although no significant events occurred, two events are conditionally significant. The human errors occurring during the year were due to maintenance errors (5 events), design errors (3 events), administrative errors (1 event), and installation errors (1 event).

The first conditionally significant event, which occurred in January, involved a hydrogen explosion in the condensate demineralizer regeneration system acid day tank (Ltr. 1/24/75). No one was injured. The hydrogen was formed by moisture leaking into a tank of concentrated sulfuric acid which was ignited by a spark caused by welders working in the area. The most noteworthy (and conditionally significant) human error was an administrative error, that occurred on March 30, when radioactive liquids were discharged twice from an unmonitored sump. Previous samples from the sump showed no activity and none was anticipated. Procedures were modified to prevent a recurrence.

More valve problems occurred in 1975. In particular, two events involved degradation of safety/relief valves. In one incident (AO-75-9) a safety/relief valve failed to reseat due to a malfunction of two pilot valves.[7] The reactor pressure dropped to 160 psig. During the blowdown, the reactor cooldown rate reached 155°F/h, well in excess of the limit of 100°F/h. No damage to reactor components occurred. Both pilot valves were replaced. In a second incident (AO-75-17) the bellows integrity of two safety relief valves could not be verified. Instrument air lines had become fouled and had to be cleaned.

1976

Five of the 28 reportable events that occurred at Millstone 1 in 1976 are significant. Three of the significant events involve the gas-turbine generator (RO-76-10, RO-76-12, and RO-76-29). One failure of the generator occurred during a total loss of offsite power. Millstone 1 experienced several problems with the isolation condenser, beginning in February (RO-76-4) and continuing throughout the year with various valve and control troubles.

On November 17, 1976, an inadvertent criticality during a shutdown margin test occurred when an operator selected the wrong control rods for the test (RO-76-34).

It should also be noted that the majority (16 events) of the environmental violations at Millstone 1 occurred in 1976. These events are attributed to an unexpected increase in the abundance of marine life around the plant during the year.

A single conditionally significant event occurred on April 23, 1976 when an excessive stack gas release occurred due to fuel clad perforations.

1977

The third largest number of reportable events were recorded in 1977 (38). Two of these events involved safety/relief valve (SRV) failures. Four events involved failures in the emergency electrical power systems, three of them involving the diesel generator. On two occasions, the diesel generator failed as a result of a fuel oil leak, and on the third the diesel generator was declared inoperable for an unknown cause. There was only one gas turbine generator failure in 1977. A spurious noise signal in the control system caused the gas turbine generator's startup test to be stopped.

Both of the significant events that occurred in 1977 took place in December. The first resulted in a total loss of emergency power when the diesel generator was declared inoperable at the same time the gas-turbine generator was unavailable. The second involved the off-gas system. The stack release rate increased after an explosion in the system. Four hours later, another explosion occurred. The second detonation occurred at the base of the stack. Two workers were injured but the safety of the plant was not challenged.

Three conditionally significant events that occurred in 1977 involved various systems. In the first event, both stack gas monitors were inoperable due to a blown fuse in the power supply. On November 18 the reactor cooldown rate exceeded the allowable limit when a safety/relief valve lifted at a low pressure. The final event occurred when a maintenance foreman inadvertently short circuited a valve operator on a LPCI valve.

1978

Although there was a large number of reportable events in 1978 (28 events), none of them are significant. The majority of the events involved setpoint drifts (10 events) or single failures in redundant systems (9 events).

Of the 12 human errors that occurred in 1978, eight were due to maintenance. The most notable error, and the only conditionally significant event, is an administrative error. On July 25, the containment was purged with a high radiation signal to the containment purge valves bypassed. The high radiation override also bypasses the containment isolation actuation signal to the purge valves. On 12 occasions, the

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purge interval was greater than four hours. The operability requirements for these valves was not discussed in the procedures.

1979

In 1979, the fourth highest number of reportable events (36 events) over the operating experience of the plant were reported. On September 14, 1979, it was discovered that a design error allowed loss of power to the ECCS to go undetected under a certain electrical distribution arrangement (LER 79-26). The logic was changed to eliminate this possibility. This event is classified as significant to safety.

Three conditionally significant events occurred during 1979. On February 26, a pressure relief valve lifted prematurely and then failed to reseat. An uncontrolled blowdown and excessive cooldown rate resulted. The cooldown rate limit of 100°/h was exceeded by 5°. The overall effect on reactor pressure vessel structural integrity was considered to be small.

Two other conditionally significant events occurred due to human errors. On February 1, an operator operated the plant in a degraded mode of operation. One control rod had an inoperable accumulator and another control rod in the same array was electrically disarmed. The disarming of the second control rod was an oversight by the operator.

Defective procedures led to the sodium pentaborate concentration in the standby liquid control tanks being less than the allowable limit on July 13, 1979. The concentration was increased immediately upon discovery and procedural changes were made to preclude a recurrence.

1980

Seventeen reportable events were recorded at Millstone 1 in 1980. Problems involving weld cracks in two main steam lines and in the condenser nozzle were reported. The cracks were discovered during the fall refueling outage. No significant or conditionally significant events occurred during 1980.

1981

In 1981, 44 events were reported, which constitutes the largest number of reportable events submitted by Millstone during a single year of operation. Instrumentation and control systems were the most reported systems (14 events). Half of these events were due to set point drifts. The emergency generator system accounted for six events. All six of the events involved a diesel generator, a gas turbine generator, or both. The event that involved both generators was considered significant (LER 81-02). On April 3, personnel discovered that a single relay failure in the loss of normal power circuits could prevent the diesel generator and the gas turbine generator from energizing the emergency buses. This was the result of a design oversight.

The second significant event occurred on September 15 (LER 81-25). Voltage fluctuations in the 125 V DC electrical system resulted in an isolation of the ATWS system. This caused both recirculation pumps to trip. This condition was not annunciated in the control room and consequently, control room personnel were not immediately alerted to the incident.

Eight conditionally significant events occurred in 1981. Three events involved radioactive liquid waste releases. Gas-turbine generator failures accounted for two events. The remaining three events involved a cracked pipe weld, two closed containment isolation valves, and a high cooldown rate during a manual blow down.

1982

Although there was a large number of reportable events in 1982 (35 events), none of them are significant to safety. Nineteen events resulted from inherent error. Nine of these events involve set point drift. Thirteen events resulted from human errors. Human errors include operation errors (4 events), installation errors (3 events), maintenance errors (3 events), and fabrication errors (3 events).

Of the 35 reportable events that occurred in 1982, thirteen are conditionally significant to safety. The gas-turbine generator was involved in four events. Operator failures involving the stack gas monitoring system accounted for two events. Two events involved radiation levels that were above Technical Specifications levels in marine life. The remaining events involved a stress crack in a sparger weld, set point drift in 5 safety relief valves, melted relays in the reactor protection system, a fire in a switcher, and multiple breaker failures due to water damage.

1983

The second largest number of reportable events occurred in 1983 (39 events). Instrumentation and control systems were the most reported systems (13 events). Over half (8 events) of these events were due to set point drifts. The emergency power system accounted for six events. Five of these events involved the gas-turbine generator. No significant events occurred during 1983.

A total of seven conditionally significant events occurred during 1983. The emergency generator system was involved in four of the events. Improper calibration of time delay relays for the turbine-generator accounted for two events. The remaining event involved a switch failure in one channel of the average power range monitor.

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1984

In 1984 the smallest number of reportable events (11 events) for any full year of operation occurred. Half of the reportable events were caused by maintenance problems. For the third consecutive year no significant events occurred.

The isolation condenser was involved in two of the five conditionally significant events that occurred in 1984. Another conditionally significant event involved three safety relief valves that failed to open during a bench test due to set point drift. This is a recurring problem for BWRs. The remaining events include the failure of a fire detector string due to low supervisory air pressure and welds that have intergranular stress corrosion cracking.

3.3.1.1 Systems involved in reportable events. A compilation of all reportable events by system and year is presented in Table 3.8. Some systems which were not involved in the reports were omitted. There are no discernible time-dependent trends among the systems identified. Most of the reports involved the following systems: reactor coolant (33.4%), instrumentation and controls (21.3%), engineered safety features (18.1%), and electrical power (12.1%). Each of these systems is discussed in the following subsections.

3.3.1.1.1 Reactor coolant system. The designation of reactor coolant system encompasses a broad range of heat transfer-related equipment in the reactor. For Millstone 1, this system includes all steam line monitors and valves, especially safety/relief valves; the isolation condenser; main steam isolation valves; pressure regulator; feedwater system and controls; and recirculation system. One-third (33.4%) of the reportable events involved the reactor coolant system (135 events). A large majority of reports involving the reactor coolant system concerned valve failures during tests, failures of the electrical and mechanical pressure regulators, and failures of various coolant parameter monitoring components. Excessive pipe movement was reported several times but no apparent damage resulted.

Eleven weld-related failures were reported for Millstone 1. Extensive work was performed on the feedwater spargers, and all spargers have been replaced at least once. Cracks in BWRs are a common problem, and Millstone 1 has been no exception. Cracking at Millstone 1 is analyzed in greater detail in Sect. 3.3.3.1.

The isolation condenser provided several problems at Millstone 1. The isolation condenser valves failed twelve times during the review period. These failures are discussed in more detail in Sect. 3.3.3.5. The condenser itself had to be completely retubed in 1976 (RO 76-4). This incident is discussed in Sect. 3.3.2.1.

The electrical or mechanical pressure regulator failed four times from 1970 to 1972. Three of the failures involved only the electrical pressure regulator (AOs 71-12, 71-27, 72-2) and were inconsequential

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Table 3.8. Summary of systems involved in reportable events at Millstone 1

System	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Totals
Reactor	1	1	1	4			4	1	1	5	1	1	1	1		22
Reactor coolant	4	8	14	8	8	9	10	14	7	11	7	7	9	11	8	135
Engineered safety features		12	4	3	4	1	4	7	4	8	2	9	6	4	5	73
Instrumentation and controls		4	7	2		6	3	7	7	10	6	14	5	13	2	86
Electrical power	2	7	4	2		3	5	4	4	2		6	8	1	1	49
Fuel handling									1							1
Auxiliary water		4			1	3			1			1	5	3		18
Steam and power	3	3	1		1	1	1	1	3			1	1	7		23
Radiation protection								4		2	1	1		1	1	10
Radioactive waste management						2						2	2			6
No system applicable			1	1	2	1	1	1	2		1			1		11
Other Auxiliary systems										1		2		2	1	6
TOTAL	10	39	32	20	16	26	28	39	30	39	18	44	37	44	18	440

because the mechanical pressure regulator served as a backup. A fourth failure (AO 71-20) resulted in a reactor blowdown.

Along with resulting in a reactor blowdown, the above event was one of five that produced a high cooldown rate (AO 71-20, AO 75-09, LER 77-33, LER 79-05, LER 81-04). The October 10, 1971 blowdown cooled down the reactor moderator 135° in 18 min (450°F/h). The other excessive cooldown rates ranged from 105°F/h to 210°F/h. A rapid cooldown rate is of continuing concern due to the added stress placed on the reactor vessel.

On March 10, 1978, two uncontrolled blowdowns occurred. A review of the temperature charts for both blowdowns revealed that the average rate of reactor temperature change, over 1 hour, was less than the technical specifications limit (100°F/h). The first blowdown resulted when a safety/relief valve failed to close. The reactor was manually scrammed. Reactor pressure was allowed to increase due to other activities in the plant. The same safety/relief valve lifted prematurely resulting in another blowdown.

3.3.1.1.2 Instrumentation and control. This system is comprised of all reactor safety and trip instrumentation as well as all control functions for normal operation. Its frequent involvement (21.3% or 86 events) in reportable events can be attributed to instrument set-point drift, mis-calibration, and spurious trips. No safety functions were compromised as a result of these problems.

On February 16, 1982, the closure of a main steam isolation valve failed to generate a reactor protection system scram signal (LER 82-15). When the MSIV was closed, the relay did not deenergize. This prevented the reactor protection relay from deenergizing which in turn prevented the generation of a scram signal (two-out-of-four MSIV closure signals are required for an automatic scram). The armature on the limit switch was out of adjustment. Two events of this nature occurred previously on June 18, 1981 (LER 81-16) and on August 18, 1981 (LER 81-22).

3.3.1.1.3 Engineered safety features. The engineered safety features system was involved in 71 of the reportable events (18.1%). Most failures occurred during testing of the ECCS and the isolation condenser. An unusually high number of reports appeared in 1971 when problems surfaced during tests of the core spray valves. On January 19, 1971, the core spray valves were tested at 1000 psig instead of the core spray operating pressure of 300 psig (AO 71-01). The valves all failed and the ECCS was declared inoperable. The torque setting on the switches was too low and had to be reset. On March 31, 1971, the motor operator on an LPCI valve failed due to a short in its windings. The motor was replaced. On September 18, 1971, another LPCI valve motor operator burned out and was replaced by a larger motor.

Overall, 30 of the reportable events in this system resulted from human errors. Five of the events that resulted from human errors are of

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interest. On April 19, 1981, maintenance personnel left two containment isolation valves in the closed position (LER 81-03). The closure of these valves isolated the high drywell pressure switch associated with the ECCS and RPS initiation. While investigating problems with a LPCI motor-operated valve, a maintenance foreman opened the wrong breaker (RO 77-38). The open breaker caused the LPCI injection valve to become inoperable. Defective procedures allowed the boron concentration in the standby liquid control tanks to be less than the technical specifications limit (LER 79-18). On September 14, 1979, personnel discovered a design error in the power distribution to the ECCS buses (LER 79-26). A loss of power could occur to the supply for the ECCS electrical buses without the loss of normal power initiation logic being able to sense the loss. The fifth event was the previously mentioned event on January 19, 1971 (AO 71-01). Four core spray valves failed when the system was tested at 1000 psig rather than its operating pressure of 300 psig.

3.3.1.1.4 Electrical power system. Thirty-seven of the 49 reportable events concerning the electrical power systems were attributed to failures of the gas turbine generator. These failures in the electrical power system comprised 12.1% of all reported events for Millstone 1.

The emergency power system consists of a gas turbine generator and a diesel generator. Upon loss of offsite power, the gas turbine generator is required to supply power to the Feedwater Coolant Injection (FWCI) System. Therefore, when the gas turbine generator fails, the FWCI system is unavailable. The FWCI system or the isolation condenser are provisions for emergency core cooling during a loss of normal auxiliary power. On two occasions (RO 76-10, RO 76-12) the gas turbine generator was declared inoperable while the isolation condenser was out of service. The plant was immediately shut down on both occasions. Further details are given in Sect. 3.3.2.2.

On December 10, 1977, the diesel generator was declared inoperable while the gas turbine generator was out of service (RO 77-39). Consequently, all emergency power systems were unavailable. Further investigation of the emergency power system on April 3, 1981, revealed that a single failure mode existed (LER 81-02). A single relay failure in the loss of normal power circuits would inhibit the diesel generator and the gas turbine generator from loading the emergency buses.

Millstone also experienced a loss of offsite power when salt built up on the 345 kV lines and insulators as hurricane Belle passed (RO 76-29). The diesel generator and gas turbine generator were being run without loads as a precaution. When normal power was lost, the gas turbine tripped and the diesel generator loaded the emergency buses. The gas turbine tripped twice. The first trip occurred upon loss of the AC auxiliaries which resulted from loss of offsite power. The second trip was attributable to a loss of DC control power. The loss of power was caused by the gas turbine running on DC auxiliaries which it is not designed to do.

3.3.1.2 Causes of reportable events. Table 3.9 presents a summary of causes of reportable events at Millstone 1. Over half of all reportable events (231) at the plant were attributed to inherent failure. Inherent failures include set point drift, wear out, and other failures for which no specific cause was identified.

Over the operating experience reviewed, human error was responsible for almost half of all reportable events (173 events). Administrative, design, fabrication, installation, maintenance, and operator errors are all considered human errors. Human errors played an important role in events categorized as significant at Millstone 1. These human errors involved design, administrative, and maintenance errors. An examination of causes of significant events revealed that 11 of the 13 significant events were attributed to human errors. The last 2 events resulted from inherent failures.

3.3.2 Review of significant events

The analysis of the operating history of Millstone 1 examined reported events to find those occurrences which represented significant threats to continued safe operation or to systems designed to mitigate transient conditions. Reportable events were classified as significant if they met one or more of the criteria delineated in Sect. 2.4 Reportable Events, of this report. A description of the use of the significance categories is found in Appendix B.

Thirteen events at Millstone 1 met these criteria for classification as significant. Table 3.10 summarizes the significance categories assigned to these events. Table 3.11 summarizes the significant events which occurred at Millstone 1. The total number shown in the table, (18), is greater than the actual number of significant events, (13), because (5) events involved multiple significance categories. The events classified as significant are:

- loss of the isolation condenser (1 event),
- loss of provisions for emergency core cooling during a loss of normal power (2 events),
- ECCS failures (2 events),
- loss of offsite power with partial loss of emergency power (1 event),
- loss of emergency power (2 events),
- inadvertent criticality (1 event),
- control rod drive accumulator replacements (1 event),
- recirculation pumps trip with no alarm given (1 event),
- loss of pressure control followed by a blowdown (1 event), and
- hydrogen explosion in the off-gas system (1 event).

3.3.2.1 Loss of the isolation condenser. On February 12, 1976, the plant shut down due to arcing of the main transformer during a storm.[8,9] Normal post-shutdown pressure transients caused the main steam isolation valves to close. As a result of this, pressure

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Table 3.9 Causes of Reportable events for Millstone 1

Cause	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Totals
Administrative		1				2	2	1	1	2		2		1		12
Design	4	8	3	2	4	3	4	4	2	2	2	3				41
Fabrication											1		3	0		4
Inherent failure	2	8	19	10	7	15	13	24	16	24	9	33	21	28	2	231
Installation	3	5	2	1	1	2	2	2	1	3	2		3	1	1	29
Lightning		1														1
Maintenance	1	6	7	6	4	5	7	4	8	2	3	3	2	7	5	70
Operator	1	2		1			1	1		2		3	4	2	0	17
Weather								1								1
TOTAL	11	31	31	20	16	27	29	37	28	35	17	44	33	39	8	406

Table 3.10 Summary of significant events at Millstone 1

Significance category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Totals
S1							2	1								3
S2							1									1
S3																0
S4												1				1
S5																0
S6																0
S7		2					5	1		1		1				10
S8							2									2
S9								1								1
TOTAL	0	2	0	0	0	0	10	3	0	1	0	2	0	0	0	18

Table 3.11. Tabulation of significant events at Millstone 1

Report section	Report number	Accession number	Significance	Event description
3.3.2.3	AO 71-01	62296	S7	Four simultaneous valve failures rendered ECCS inoperable
3.3.2.9	AO 71-20	66996	S7	Failure of steam turbine bypass valve caused a blowdown
3.3.2.7		77956	S7, S2	Control rod drive accumulators require replacement
3.3.2.1	RO 76-04	111647	S7	Tube failures in Isolation Condenser resulted in radiation release
3.3.2.2	RO 76-10	112309	S7, S1	Gas turbine generator inoperable while Isolation Conderser inoperable
3.3.2.2	RO 76-12	112310	S7, S1	Gas turbine generator inoperable while Isolation Condenser inoperable
3.3.2.4	RO 76-29	116780	S7, S8	Gas turbine genertor tripped on incorrect feed during a LOOP
3.3.2.6	RO 76-34	120436	S8	Unplanned criticality achieved when wrong control rods selected
3.3.2.5	RO 77-39	144187	S7, S1	Diesel generator and gas turbine generator inoperable simultaneously
3.3.2.10	RO 77-40	144186	S9	Two hydrogen explosions in the off-gas system occurred
3.3.2.3	LER 79-26	151912	S7	Potential existed for loss of power to ECCS to go undetected
3.3.2.5	LER 81-02	165884	S7	Potential existed for a single failure mode in the emergency power system
3.3.2.8	LER 81-25	169185	S4	Both recirculation pumps tripped, ATWS isolated, no alarm

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increased momentarily in the isolation condenser, causing an isolation condenser tube to fail (RO 76-4).

Steam leaked into the shell side of the condenser and was vented into the atmosphere. The operators did not recognize the cause of the steam release until 1 h and 16 min after the shutdown, when the control room received a high radiation alarm from the steam vent line. The isolation condenser was then isolated and the steam release halted.

An area of approximately one acre, all inside the fenced area, was contaminated. No reportable personnel exposures resulted from the release of contaminants. Eight minutes after the reactor trip, the main condenser was valved in to act as a primary heat sink. Recovery from the transient proceeded smoothly.

Examination of the condenser revealed a tube with a 1-in. by 2-in. hole. The failure resulted from stress corrosion cracking. The corrosion was attributed to the intrusion of chlorides from a previous failure of the main condenser. Other tubes in the isolation condenser were retubed with Inconel 600 tube material.

3.3.2.2 Loss of provisions for emergency core cooling during a loss of normal auxiliary power. During a loss of offsite power, two methods of heat removal are available. Either the isolation condenser or the feedwater coolant injection system (FWCI) in conjunction with the pressure relief valves can remove decay heat.[10] The isolation condenser system operates by natural circulation without the need for driving power other than the DC electrical system used to place the condenser system in operation. The operation of the FWCI system requires an AC power source. Given the loss of offsite power, the gas turbine generator provides the driving force to the FWCI system. The loss of the gas turbine generator would mean the loss of the FWCI system, one loop of the LPCI system, and one loop of the core spray system.

On two occasions within a one-week period, the gas turbine generator and the isolation condenser were unavailable simultaneously (RO 76-10, RO 76-12). Consequently, the FWCI and isolation condenser were simultaneously unavailable.[11] The isolation condenser system was inoperable due to retubing activities required after the pressure transient on February 12, 1976. On March 8, the gas turbine generator failed to start due to a maladjusted governor. The governor being out of adjustment was attributed to the higher test frequency of the gas turbine while the isolation condenser was inoperable. The governor was readjusted and the gas turbine declared operable after a successful start.

On March 15, the gas turbine again failed to start due to problems with the governor. The electric governor-magnetic board which provides signal conditioning of various input signals and an output signal to the gas turbine speed control system failed. This failure was the result of the higher test frequency of the gas turbine generator.

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3.3.2.3 ECCS failures. Two events challenged the integrity of the ECCS.

On January 19, 1971, operability tests of the core spray and LPCI systems revealed several component failures. The LPCI system and both core spray loops are each designed to be capable of supplying the required emergency core cooling in the event of a large pipe break, with or without normal offsite power. At least one of these systems must be operable during operation of the plant. Two core spray injection valves, one on each core spray loop, failed. Testing of the LPCI system revealed two other valves that would not operate properly. After discovering these failed valves, a turbine control valve unexpectedly closed with the reactor at full power. The other three turbine control valves opened wider to compensate. Pressure oscillations of 25% caused reactor power fluctuations of 8%. As soon as control was switched from the mechanical pressure regulator to the electrical pressure regulator, the oscillations stopped. The four valves in the ECCS failed because their torque switches were set too low.[12]

On September 14, 1979, a situation arose that was not specifically considered in the safety analysis report. A review of the control circuitry and logic associated with the 4160 V circuit breakers revealed that a loss of power supply to the ECCS electrical buses could occur. The Loss of Normal Power (LNP) initiation logic senses the loss of power and immediately starts the emergency power sources. Because of a design error in the logic system, the loss of power would not have been sensed, and the emergency power system would not have been automatically started. A modification to the LNP initiation logic corrected the design error.

3.3.2.4 Loss of offsite power with partial loss of emergency power. On August 10, 1976, the Millstone 1 plant lost all offsite power due to salt buildup on the 354 kV lines and insulators.[13] Prior to the loss of power, the gas turbine generator and the diesel generator had been running without a load, as a precaution during storm conditions. The plant had been operating at 45% power and tripped upon the loss of offsite power. The gas turbine generator failed on the loss of normal power; however, the diesel generator accepted load successfully. The gas turbine generator restarted and ran for ~8 min before tripping again (RO 76-29).[11]

Investigation revealed that operator error caused both failures of the gas turbine generator. The generator has both AC and DC auxiliaries. The gas turbine generator is the primary source of AC power for its own auxiliaries once it is up to rated speed and voltage. The design also provides for an alternate source of AC power during testing. Transfer between the two sources of power is accomplished by a manually operated throwover switch.

During precautionary operation of the gas turbine generator, the operators performed a bimonthly surveillance test using the alternate source of AC power. At the conclusion of the test, the throwover switch

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was not returned to its normal (primary source) position. Upon loss of offsite power and unit trip, the alternate source of AC power was lost, causing the gas turbine generator to trip.

In its normal position, the throwover switch also enables automatic transfer from the DC auxiliaries (only used to start the unit) to the AC auxiliaries. The unit restarted after the initial trip. Transfer from DC auxiliaries to AC was not accomplished. The unit ran for 8 min and then tripped a second time when the DC batteries failed.

The following corrective measures were implemented to prevent recurrence of the event:[14]

1. The procedure for testing the gas turbine was rewritten so that the AC auxiliaries are energized from the primary source during surveillance testing.
2. The throwover switch was locked into its normal position.
3. A breaker position monitoring circuit was installed to alert the operators of an incorrect alignment of the power sources for the AC auxiliaries.
4. Operating procedures were revised to no longer require starting of the diesel generator and gas turbine generator during storm conditions.

The gas turbine generator serves as the emergency power source of 4.16 kV power for the feedwater coolant injection (FWCI) pumps and control, which are part of the ECCS. This event seriously compromised the safety of the plant. For over 3 h the single diesel generator was the only source of A/C power to Millstone 1. The isolation condenser, which requires only DC power, was used to cool the core. The isolation condenser had experienced severe problems only 6 months prior to this incident (see Sect. 3.3.2.1). Had it failed during the loss of normal power, all the remaining core cooling features would have been entirely dependent on the remaining diesel generator for power. In general, diesel generators have had historically high failure rates; however, the one diesel generator at Millstone 1 has a very good performance record.

3.3.2.5 Loss of emergency power. Millstone 1 experienced one complete loss of emergency power. Later it was discovered that a previously undetected single failure mode existed in the emergency power system.

On December 10, 1977, a test of the FWCI system revealed a fault in the gas turbine generator's governor (RO 77-39). The emergency power system consists of the gas turbine generator and a diesel generator. When the diesel generator was tested for operability it failed the operability test.[11] The cause was reported as unknown.

A single failure mode of the emergency power system was discovered through a fault tree analysis of the electrical control circuitry (LER 81-02). The analysis showed that a single relay failure in either of the two LNP circuits could prevent both the gas turbine generator and

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the diesel generator from energizing the 4160 V emergency buses. The relay failure would occur if the contacts of the time delay relay in either LNP circuit failed to reopen following a loss of normal power initiation signal. This would result in a continuous trip signal to all 4160 V and certain 480 V circuit breakers. In this situation, the buses could be energized by removing the control circuit fuses and manually operating the circuit breakers. The installation of a second time delay relay corrected the design error.

3.3.2.6 Inadvertent criticality. While performing a shutdown margin test on November 12, 1976, an inadvertent criticality and reactor trip occurred (RO 76-34). An operator error in selecting rods for the test caused the unplanned criticality.[15]

The test is performed by positioning the highest worth rod (46-23) to notch position 10, the diagonal control rod (42-19) is then withdrawn to notch position 10, followed by full withdrawal of the maximum worth rod. The licensed reactor operator incorrectly notched out adjacent control rod 46-19 (instead of 42-19, the correct and designated rod). Without recognizing his selection error, he then withdrew the highest worth rod. The reactor tripped on high flux.

At the time of the incident, the rod worth minimizer had been bypassed and the operator was performing the test by himself — a violation of test procedures. The circumstances of the trip were reported to the supervisor who dismissed the condition as "spurious noise."

A second test was performed contrary to procedural requirements concerning evaluation of instrumentation. Again, the operator erroneously withdrew rod 46-19. Subsequent withdrawal of rod 46-23 resulted in a flux increase, and the high worth rod reinserted to avert a second trip. Following the recognition of the previous rod selection errors, a third shutdown margin test was successfully performed. Procedural requirements were again violated as the third test was performed without assessing the potential for radiation exposure or fuel damage caused by the two criticalities. The incident was not reported to the appropriate management personnel until their arrival on the next work day, another violation of procedures.

Refueling and fuel movement were suspended for three days by the NRC. No personnel exposures occurred. The licenses of the two operators involved were suspended.

This incident represents the worst reported operator error committed during the operating experience of Millstone 1. The multiple procedural errors resulted in the NRC levying a $15,000 fine.

3.3.2.7 Control rod drive accumulators require replacement. In January 1973, two accumulators gave indications of leaking water into the instrumentation block. Investigation revealed that the nickel and chromium plating had flaked from areas of the inner walls of the two accumulators. The discovery prompted the inspection of the other

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143 accumulators. All had at least minor plating defects, most of which were blisters or pits. Only six of the accumulators had amounts of blistering or flaking that were sufficient to possibly impair the operation of the control rod drive mechanism. These six were replaced with new ones. Flushing the entire control rod drive hydraulic system cleaned the system of foreign particles. Millstone 1 implemented a program for close monitoring of the instrumentation and promptly investigating any abnormalities in the system.[6] No events of this type have occurred since the new program was implemented.

3.3.2.8 Recirculation pumps trip with no alarm given. On September 15, 1981, voltage fluctuations in the 125 V DC electrical system resulted in spurious isolation of the Anticipated Transient Without Scram (ATWS) system (LER 81-25). Reenergizing the ATWS system caused an automatic trip of both recirculation pumps. Since the pumps were operating at minimum speed (reactor power was at 1%), pump coastdown and natural circulation maintained recirculation flow. With no significant change in the differential pressure across the recirculation pumps and no annunciated alarm for recirculation pump trip, control room personnel were not immediately aware of the event.

The forced recirculation flow is required to provide mixing of feedwater entering the reactor vessel to mitigate the consequences of rapid changes in reactor moderator density. The flow also eliminates the potential for high local reactor vessel stresses due to thermal stratification of reactor coolant. Although natural circulation flow provides some mixing, forced circulation is required to maintain the parameters within acceptable limits at high power levels.

The effects of no forced circulation were analyzed with respect to fuel and reactor vessel thermal effects for this event. The effects were negligible due to the low reactor power level and the short amount of time at which there was no forced circulation flow before the reactor scram occurred. An annunciator was installed off the recirculation pump field breaker to alert control room personnel of a recirculation pump trip. Additionally, after the ATWS system isolates, operator action is required to reset the system.

3.3.2.9 Loss of pressure control followed by a blowdown. On October 10, 1971, the Millstone 1 plant experienced a pressure transient followed by a blowdown of 75,000 gal of water to the torus (AO 71-20). With the reactor at 100% power, the electric pressure regulator caused the pressure to rise to 1040 psig. The operator placed the mechanical pressure regulator into service, but this did not mitigate the transient. The reactor scrammed on a high flux reading on the average power range monitor (APRM). The turbine tripped and the turbine bypass valves opened. As the pressure of the vessel began to drop, the number one turbine valve failed to close. The main steam isolation valves closed, but pressure continued to decrease in the vessel. It was then discovered that a relief valve that opened at the time of the scram failed to reseat.

The stuck-open valve seated when pressure dropped to 263 psig. The isolation condenser was then put into service and a normal cooldown proceeded.

During the transient the reactor pressure dropped from 1040 psig to 263 psig, and the moderator temperature dropped from 525°F to 390°F in 18 min. The maximum cooldown rate as measured by the moderator temperature was 100°F/hr when measured over the first hour of the transient. This represents a significant stress on the vessel even though no technical specifications were violated. General Electric determined that the vessel blowdown conditions would not affect the integrity of the vessel.

Failure of the electric pressure relief valve was attributed to a loose dashpot connection to the pressure regulator torque tube.

The relief valve itself experienced two failures. First, the valve opened at 1040 psig, instead of 1095 psig. The set point change was caused by relaxation of the set pressure-adjustment spring due to its exposure to temperatures near 550°F. The valves had been insulated with asbestos blankets, and the reduction in heat transfer ability caused the valve internals to be exposed to elevated temperatures. This insulation was partially removed. Second, the relief valve failed to reseat after opening. This was attributed to leaking of the pilot valve (caused by lower setpoint) and the erosion of the pilot-valve disk.

3.3.2.10 Hydrogen explosion in the off-gas system. On December 13, 1977, two hydrogen explosions occurred at Millstone 1. The first explosion occurred at 9:30 a.m. and was mostly confined to the off-gas system. Damage was minor and the plant reduced power while repairs commenced. A second explosion occurred at 1:00 p.m., outside the off-gas system, causing considerably more damage and injuring personnel.

The second explosion occurred when the Millstone personnel were unsuccessful in restoring water to the loop seals after the first explosion. Without these seals, the gas accumulated and was ignited by a spark from the liquid level switch in the stack base sump. The explosion propelled the door of the room into a warehouse 200 ft away, breached the reinforced concrete ceiling beams, damaged supports of a radiation monitor for the stack, and cracked the stack. The control room was alerted to the second detonation of hydrogen. One man was injured and a small, uncontrolled release of radiation resulted.

Off gas system explosions are a generic problem in BWRs, but most explosions are confined inside the off-gas system, which is designed to accommodate the effects of a detonation. However, explosions outside the system have occurred, resulting in damage to equipment and structures.

Immediately after the event, the NRC required all BWR licensees to implement corrective measures to resolve off-gas system problems:

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1. Review the operations and maintenance procedures of the off-gas system to assure operation in accordance with all design parameters.
2. Review the adequacy of the ventilation of spaces and areas where there is piping containing explosive gases.
3. For those spaces identified, describe what action has been taken to ensure that explosive mixtures cannot accumulate, that monitoring equipment would warn of such an accumulation should it occur.
4. Describe the design features that minimize and detect the loss of liquid from loop seals, and describe operating procedures that ensure prompt detection and resealing of blown seals.
5. Review operating and emergency procedures to ensure that the operating staff has adequate guidance to respond properly to off-gas system explosions.

Particular attention was to be paid to the loop seals.

3.3.3 Analysis of Reportable Events

Using the data gathered on reportable events listed in Appendix B, specific problem areas in safety-related functions were identified:

(1) Pipe Cracking,
(2) Safety/Relief Valves failures,
(3) Stack Gas Monitor failures,
(4) Losses of Emergency Power,
(5) Isolation Condenser Valve failures,
(6) High Radioactivity Levels in Marine Life,
(7) Excessive Reactor Cooldown Rates, and
(8) Main Steam Isolation Valve failures.

3.3.3.1 Pipe cracking. Millstone 1 reported ten incidents of pipe cracking. Pipe cracks continue to be a generic problem in BWRs. The most significant cracking events occurred in 1972, 1976, 1980, and 1982. However, no safety related incident occurred at the plant as a result of pipe cracking.

In 1972, cracks were detected in the feedwater spargers. Subsequently, all spargers were replaced, a task which resulted in excessive down time for the plant. Two pipe cracking events occurred in 1976. The first event involved a nozzle-to-steam supply weld that cracked due to stress corrosion and was replaced. The two cracks in the main steam line supports were attributed to inadequate welds during installation. The supports were reinstalled. In 1982 a stress crack was found in a weld on a core spray system sparger and the weld was repaired.

The latest pipe cracking event occurred in 1984 and was identified during the refueling outage. Intergranular stress corrosion cracking was found in three welds in the core spray, cleanup, and reactor recirculation systems. The affected welds and pipe sections were repaired or replaced.

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3.3.3.2 Safety/relief valve failures. Three events involving safety/relief valves were identified for Millstone 1. In 1977 a safety/relief valve inadvertently opened. The cause for this event is not known. Both of the remaining events involve setpoint drift that was discovered during bench tests. A total of six valves (three during 1982 and three during 1984) failed to open at the set point due to high friction at the labyrinth seal. This is a generic problem for BWRs. The BWRs Owner's Group subcommittee for safety/relief valve setpoint drift is currently evaluating this problem.

3.3.3.3 Stack gas monitor failures. Millstone 1 has experienced operational problems concerning the stack gas monitor. On two occasions during 1982 an operator failed to return the monitor to the normal operating condition following the daily test. During the ISAP plant visit it was noted that a timer and an alarm has been added to the monitor to prevent recurrences of this problem. No events involving the stack gas monitor were reported after 1982. This operational problem appears to be solved.

3.3.3.4 Loss of emergency power. Millstone 1 has experienced 47 failures of the emergency generator systems and controls. Gas turbine generator failures were the dominant contributor to the degradation of the emergency power system. The gas turbine generator failed to either start or run its full mission 37 times. Five of these were failures on demand; the remainder occurred under test conditions. Table 3.12 provides descriptions of the 37 gas turbine generator failures, along with corrective actions taken to restore the unit to service.

An analysis of gas turbine generator failures reveals that 7 of the 37 failures were attributed to a faulty speed switch. This switch was totally replaced four times during the 15-year history of the plant. The most recent replacement was required in February 1979. Five of the failures of the unit were attributed to operator or procedural errors. A procedural error caused the most significant failure of the gas turbine generator (RO 76-29) which is described in more detail in Sect. 3.3.2.4.

The emergency power system at Millstone 1 consists of one diesel generator and one gas turbine generator. If normal power to the plant is lost, the FWCI can be powered only by the gas turbine generator. Failure of the gas turbine, therefore, eliminates the cooling capacity of the FWCI. The plant does have the use of an isolation condenser at all times, even during a loss of all AC power. Unit 1 currently has use of the diesel generators at unit 2 (through manual switching) but technical specifications do not take credit for these as a source of emergency power.

The plant is located on a promontory extending out to the ocean and all power lines must share the same right of way for several miles. This increases the chance of losing all offsite power due to common cause failures. Despite the potential for loss of emergency power, the Millstone 1 plant has experienced few failures of its diesel generator and only one complete loss of offsite power (AO 76-29).

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Table 3.12. Gas turbine generator failures at Millstone 1

Report No.	Event date	Event description and problem solution
RS 70-4	11-8-70	Gas turbine generator (GTG) fails to start due to low pressure in the lube oil pump. Start-up governing system adjusted.
RS 70-4	12-4-70 (reported)	GTG fails to start due to low pressure in lube oil pump. Two additional immersion heaters installed, set points readjusted.
RS 70-4	1-8-71 (reported)	GTG fails to start within 48 s due to installation error of lube oil discharge line. Line reinstalled.
AO 71-5	2-21-71	GTG fails to start after main turbine trip due to blown fuse and faulty relay. Fuse and relay replaced.
AO 71-8	4-22-71	GTG inoperative due to procedural errors. An operator left a switch in the wrong position. Operators instructed as to proper procedure.
AO 71-12	5-27-71	GTG failed to reach startup speed due to a short circuit in speed switch. Switch replaced.
AO 71-24	11-2-71	GTG failed to ignite due to loose solder connections on a transistor speed switch. Transistor replaced.
AO 71-25	11-30-71	Procedural error caused a loss of heating of the lube oil for the GTG. Operators instructed as to proper operation.
AO 72-3	2-4-72	GTG failed to start after plant trip due to wiring errors in vibration monitor package. Errors fixed.
AO 72-11	3-9-72	GTG failed to start after plant trip due to faulty transistor in speed switch. All transistors replaced.
AO 73-5	4-5-73	Operator disabled GTG by turning wrong controller. Cover placed over controller.
AO 75-4	1-29-75	GTG removed from service to replace faulty relay.
AO 75-8	5-20-75	High generator lube oil temperature due to incorrect valving caused trip of GTG. Valves locked into correct position.

Table 3.12. (Continued)

Report No.	Event date	Event description and problem solution
AO 76-8	2-29-75	GTG did not start due to improper governor setting. Governor readjusted.
AO 76-10	3-8-76	During daily testing of GTG, unit failed to start due to improper governor setting. Governor readjusted.
RO 76-12	3-15-76	GTG declared inoperable due to governor failure. Switches replaced.
AO 76-29	8-10-76	GTG became inoperable when it could not accept plant load on reactor trip. Cause was incorrect AC feed to GTG auxiliaries. AC feed restructured.
AO 76-30	8-31-76	GTG inoperable on overspeed condition due to faulty speed switch. Switch replaced.
LER 77-27	9-9-77	Spurious noise causes GTG to fail to complete startup sequence. No repair reported.
LER 78-12	5-19-78	GTG failed to start due to incorrect fuel scheduling. No repair reported.
LER 78-14	6-13-78	GTG trips on overspeed due to defective speed switch channel. Speed switch assembly replaced.
LER 78-21	9-14-78	GTG tripped due to faulty speed switch. No repair reported.
LER 78-29	11-22-78	GTG inoperable due to opening of lube oil pump circuit breaker. Breaker indicator bulb replaced.
LER 79-7	2-14-79	GTG fails to start due to faulty speed switch. Switch replaced.
LER 81-20	7-14-81	GTG failed to start due to rust in the air motor start valve. The valve was cleaned.
LER 81-28	8-11-81	GTG output breaker failed to close due to corrosion on the automatic voltage regulator. The contacting surfaces were cleaned.
LER 81-31	9-10-81	GTG output breaker failed to close due to a wire wound ceramic resistor which failed open. The resistor was replaced.

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Table 3.12. (Continued)

Report No.	Event date	Event description and problem solution
LER 81-41	12-8-81	GTG governor failed due to contaminated oil. The oil system was flushed with clean oil.
LER 82-11	5-8-82	GTG declared inoperable due to blown fuse for AC lube oil pump. The undervoltage relay and fuse were replaced.
LER 82-13	6-15-82	Air pressure regulating valve for GTG fails due to rust in starting air system. Valve was replaced.
LER 82-17	8-17-82	GTG fails 2 start tests due to rust in air pressure regulating valve. Valve was replaced.
LER 82-32	12-17-82	GTG fails to start due to generator overspeed. Setpoints for the stator vane controller, fuel valve servo-limiter, and the governor were readjusted.
LER 83-14	3-31-83	GTG fails to start due to failure of both ignitors. one ignitor was replaced.
LER 83-18	5-17-83	GTG fails to reach ready to load status due to worn ignitors. One ignitor was replaced.
LER 83-24	6-12-83	GTG declared inoperable due to failed EGR oil pump motor. The motor was replaced.
LER 83-25	7-12-83	GTG declared inoperable due to blown fuse during calibration. The fuse was replaced.
LER 83-26	8-16-83	GTG shut down due to an oil impregnated cable. The cable was replaced. Cables are now inspected during each refueling outage.

3.3.3.5 Isolation condenser valve failures. Millstone 1 experienced 12 failures of the isolation condenser valves over the time period from 1970 to 1984. The condenser isolated twice as it was placed in operation (AOs 70-5, 73-4). Both times the inboard condensate return valve was opened too wide and caused excessively high flow through the condenser. This high flow condition automatically isolates the condenser. After the first occurrence, the valve opening was restricted to reduce flow to the isolation condenser. The second failure occurred when a maintenance worker failed to properly set the valve opening restrictor after working on the valve.

Five failures have occurred with the inboard steam supply valve (1-IC-1). On December 17, 1976, the torque switch actuator setting was found to be incorrect, actuating the torque switch prematurely and not allowing the valve to move. On October 31, 1977, the breaker for the valve malfunctioned, causing the valve to be inoperable. On February 14, 1979, the valve operator gear casing was fractured, causing inoperability of the valve. On December 17, 1976, a faulty microswitch on the closing torque switch caused the valve to fail to close. This identical incident recurred on September 4, 1979. All of these failures occurred during surveillance testing, and the plant was immediately shut down after each failure.

On October 19, 1978, the condensate return isolation valve spuriously opened causing an inadvertent initiation of the isolation condenser. The initiation was then secured by an operator who closed the valve. The spurious opening signal resulted from a set point drift of two switches in separate logic channels. The set points were subsequently readjusted. On December 18, 1976, the isolation condenser inboard condensate return valve failed to close during a test. The torque switch setting was incorrect and was readjusted.

Three failures have occurred with the isolation valves for the isolation condenser. In each event, limit switch problems caused the isolation valves to fail. One event (LER 82-30) involved a failure-to-close and two events (LER 84-14 and LER 84-18) involved a failure-to-open. In each case, the limit switches were readjusted and the valves placed back in service.

3.3.3.6 High radioactivity levels in marine life. Millstone 1 reported nine incidents of higher than allowed levels of radioactive silver and cobalt in marine life during the operating history of the plant. All of those events occurred in the period from 1981 through 1984. The majority of the events (7) occurred during 1982 and 1983. In each event the levels of radioactivity measured were extremely small but did exceed the control station average activity by greater than a factor of ten.

3.3.3.7 Excessive reactor cooldown rates. Millstone 1 experienced five incidents of excessive cooldown rates throughout its operating history. Any large cooldown rate is of concern since a thermal stress is placed on the reactor vessel and the resulting fatigue is a cumulative effect. The first and most significant cooldown occurred in 1971 (AO 71-20). The moderator cooldown rate was equivalent to 450°F/h and 75,000 gal. of water was blown out of the system (see Sect. 3.3.2). The other four blowdowns that resulted in excessive cooldown rates occurred in 1975, 1977, 1979, and 1981 (RO 75-09, RO 77-33, LER 79-05, and LER 81-04, respectively). The cooldown rates ranged from 105 to 210°F/h. Three additional blowdowns occurred during the operating history but the cooldown rate for each occurrence was below the Technical Specification limit of 100°F/h (RO 77-17 and RO 78-04 with two blowdowns).

Four of the excessive cooldown rate events occurred due to safety/relief valve failures (as well as the other three blowdown events). Overall, twelve events occurred due to safety/relief valve failures. Half of the events produced no deleterious effects to the operation of the plant or to the environment. Failures included fouled instrument air lines, a clogged filter, a wiring short, a valve failing to open, and a setpoint drift. The other six events resulted in blowdowns with four of these producing excessive cooldown rates. On March 10, 1978, two blowdowns occurred but a review of the temperature charts revealed that the cooldown rate was not exceeded. Therefore, the six events represent seven blowdowns and excessive cooldowns. The failure modes of the safety-relief valves fell into two categories. The valve either lifted prematurely (4 occasions), or failed to close (3 occasions).

No excessive cooldown rate events occurred during 1982, 1983, or 1984. This fact is attributed to fewer failures of the safety/relief valves during the three-year period.

3.3.3.8 Main steam isolation valve failures. Eight of the reportable events occurred due to MSIV failures. Based upon the data available in the LER data files, recent MSIV failures are primarily related to the following causes: (1) poor quality control air to the pilot valves, and (2) binding of MSIV valve stems with the valve stem packing. These two failure modes are significant in that: (1) they identify mechanisms by which more than one MSIV may fail to close at the same time, and (2) they continue to occur even though corrective actions indicate that the technology is available to prevent such failures. At Millstone 1, four of the MSIV failures were failure-to-close with three of these due to sticking air slide valves. The fourth failure-to-close was due to a parted venting slide valve. Three failures (RO 75-29, LER 79-11, LER 80-14) were MSIV related failures but not valve failures. In 1975, a valve position switch was in the wrong position due to a relay that failed to close. A relay failed to de-energize during 3 events in 1979, 1982, and 1983 due to a maladjustment of the relay limit switch. Two failures (LER 82-6 and LER 83-10) involve slow-closing of the MSIVs during tests. One failure was due to an out-of-position hydraulic cylinder and the other was due to tight valve stem packing. The valves were reworked and returned to service. The last MSIV related failure was the failure rate test performed on two MSIVs (LER 80-14).

4. OBSERVATIONS AND CONCLUSIONS

4.1 Overall Plant Operating Experience

In general the overall record of the operating experience for Millstone 1 was judged to be better than the average for all operating BWRs in the United States, as evidenced by the above average availability and capacity factors and the relatively small number of significant reportable events. It appeared from the data that the operating performance is improving; the number of forced shutdowns experienced during the first half of the period under review was twice the number for occurrences in the second half; the number of reportable events was about the same in both the first and second halves of the period under review; and there were no significant events at all from 1981 through 1984. Of particular note, although outside the scope of this review, Millstone 1 accomplished 374 consecutive days of continuous operation before shutting down automatically on August 13, 1985.

As part of the review effort, the ISAP operations experience assessment team visited the plant. Valuable insights were gained from discussions with plant personnel and a tour of Millstone plant facilities. On the basis of the teams' observations during the plant visit it was felt that in general the plant appears to be operated in an orderly and disciplined manner, and effective mechanisms are available to assure levels of maintenance and housekeeping which should help prevent problems from occurring.

The results of the review evaluations also showed that there are some problems identifiable through trends and symptoms found in the data.

4.2 Trends and Identified Symptoms

The analysis of the operational experience addressed recurring events and symptoms and the significance of these. Observations about general trends derived from the analyses of Availability and Capacity Factors, Forced Shutdowns, and Power Reductions are discussed below. Eight specific trends are discussed.

4.2.1 Trends in Plant Availability and Capacity Factors

The cumulative availability over the operating life of BWR's presently in operation (26 plants) ranges from 55.5% to 79.9%, with the average being 68.9%. Millstone 1 compares favorably to these other BWR's, in eighth place out of the twenty-six plants, with a cumulative availability of 73.6%. Most recently the plant has shown its ability to sustain prolonged periods of operation. Such operating performance contributes to reductions in challenges to safety systems.

4.2.2 Trends in Forced Shutdowns

In general, the plant is experiencing a lowering of the number of forced shutdowns and in the consequential number of hours of outage time.

4.2.3 Trends in Power Reductions

Other than those reductions in power necessitated for locating and repairing main condenser tube leaks, no determinable trends were discerned from the power reduction event data. The increased number of occurrences for repairing main condenser tube leaks in the last 3 years is the result of the plants' efforts to minimize generation of radwaste products needing disposal. All other causes of power reductions constituted only 35% of the total, and the causes appeared random.

4.2.4 Power Reductions for Finding and Repairing Main Condenser Tube Leaks

Over the last 2 years, through 1984, there has been a significant increase in the number of power reductions which were needed to find and fix tube leaks in the main condenser. This observation was reviewed with the utility. The utility responded that when main condenser tube leaks occur there is a consequential increase in the volume of radwaste products. The tube leaks themselves do not contribute any significant effect on the safe operation of the plant. However, the utility experienced tightening constraints on the volume of radwaste products that it can ship offsite for disposal, and accordingly, the condenser tube leaks, as contributors to these volumes, became high priority items for maintenance. Further, the utility explained that it is examining possible change out of the main condenser tubes with titanium tubes with the objective of virtually eliminating the problem.

4.2.5 Gas Turbine Generator

Problems with the Gas Turbine Generator continued to occur at Millstone 1 at a steady rate. No single component failure or operational problem dominated the undependability of the Gas Turbine. Most problems were identified during the monthly tests, because few actual demands (either on a loss of offsite power or actuation of an ECCS) occurred.

The consequence of the failure of the gas turbine to operate on demand is a degradation of the ECCS, because onsite power for the FWCI is provided by the gas turbine only. Thus, there is a consequential reduction in plant capability to withstand conditions involving degraded A/C power supply.

4.2.6 Pipe Cracks

As with all BWRs, pipe cracks continued to be a problem at Millstone 1. Efforts to resolve this problem included replacing all feedwater spargers in 1972 and the reworking of cracked welds. In spite of these efforts, pipe cracking events continued to be reported in 1982 and 1984.

4.2.7 Safety/Relief Valves

During both the 1982 and 1984 refueling outages set point drift in safety/relief valves was identified as a recurring problem. This is a generic issue for BWR's that is currently being evaluated by the BWR Owners Group Subcommittee.

4.2.8 Isolation Condenser Valves

Improper functioning of isolation condenser valves was a recurring problem. Most of the problems involved steam supply valves that failed to close on demand. This type of failure had little effect on the operation of the isolation condenser but did affect the ability to isolate the containment.

4.2.9 Main Steam Isolation Valves

Another generic BWR problem that occurred at Millstone 1 was main steam isolation valve failure. Problems with MSIV's that occurred during the early years of plant operation involved sticking air slide valves. Changes were implemented that improved the quality of the air supply to the valves. Also a program of increased testing and maintenance was implemented. These measures appear effective in resolving the problem.

Problems with MSIV's in recent years primarily involved failures of limit switches. The utility stated that all MSIV limit switches have now been environmentally qualified for service, and that this should resolve the problem.

4.2.10 Radioactivity Levels in Marine Life

There was an increase in the number of reports of higher-than-allowed levels of radioactive material in marine life since 1980. It was postulated that this increase could be due to a change in reporting requirements or due to a slow buildup of radiation levels in marine life near the plant. Due to the extremely small levels of radioactive material discovered in the marine life, a buildup is not likely. The utility requested approval for a revision to its technical specifications which would raise the allowable limits and thus eliminate the need to submit reports of these extremely low levels.

4.2.11 Other Observations

Two other problem areas that were originally identified in NUREG-0824 "Integrated Plant Safety Assessment, Systematic Evaluation Program, Millstone Nuclear Power Station Unit 1" now appear to be resolved. The first involved excessive reactor cooldown rates. There were no recurrences of excessive reactor cooldown rates during the years 1980-1984 and it is concluded that this problem has been resolved. The second involved an operational difficulty with the stack gas monitor. An alarm was added to the monitor in 1982 and subsequently no further events have been reported. This operational problem appears to be resolved.

4.3 Conclusions

The findings of this review do not lead to any conclusion that there are continuing major challenges to plant safety inherent in the operations of Millstone 1. As evidenced by the record of the plants availability and capacity factors over the period of the review, and the relatively small number of significant reportable events, the operational record of Millstone 1 can be judged to be better than average.

Nevertheless, a number of problems were identified from the data. Significant recurring problems are evident in eight discrete areas. Examination of the data shows that the recurrence of two of these eight areas, failures in the stack gas monitor and high cooldown rates, has ceased. In one area involving reports of radioactivity levels in marine life that were higher than allowed, the problem was found to lie in overly conservative reporting requirements, and has been alleviated through technical specification changes. However, the other five problem areas remain as outstanding concerns. These five are:

1. Loss of emergency power supply capabilities,
2. Pipe cracks,
3. Isolation condenser valve failures,
4. MSIV failures, and
5. Safety/relief valve setpoint drift.

The data shows that the majority of the operating experience problems were confined to random events, reflecting much of the experience of other operating BWRs. No other significant problems were identified through trends or patterns in the data.

Operational review findings provide real indicators of importance which can be used in the evaluation and prioritization of regulatory topics which are to be applied to a particular plant. Accordingly, the results and conclusions from this operational experience review can be included as one of the tools for the resolution and prioritization of the Millstone 1 ISAP issues.

APPENDIX A

REVIEW OF FORCED SHUTDOWNS AND POWER REDUCTIONS

This appendix presents the data on shutdowns and power reductions in tabular form and lists the information sources. It describes how the information was encoded and how significance screening criteria were applied.

A.1 Scope

Data collected in this review include information about each forced shutdown and power reduction that occurred between 1970 and 1984. Forced shutdowns result from equipment failures that present an abnormal challenge to the unit's operation. Scheduled shutdowns for refueling and maintenance were not included. However, if the utility scheduled a refueling or maintenance outage to coincide with a shutdown that resulted from an abnormal event, that shutdown was included even though the utility reported it as scheduled. That portion of the outage time caused by the abnormal event was attributed to the shutdown and included in the compilations.

Information on power reductions provides additional detail to a previous or subsequent shutdown, or indicates a safety significant trend. The power reductions were included in the proper chronological sequence with the shutdowns in the data tables for the forced shutdowns and power reductions (Table A.1).

The table includes the following data for each event listed by year:

1. date of occurrence,
2. duration (hours),
3. power level (percent),
4. notation of whether the shutdowns were also reportable events [e.g., a license event report (LER) or abnormal occurrence report (AO)],
5. summary description of events,
6. cause of shutdown (Table A.2),
7. method of shutdown (Table A.2),
8. system that was directly involved with the shutdown or power reduction (Table A.3),
9. component directly involved with the shutdown or power reduction (Table A.4), and
10. categorization of the shutdown or power reduction.

A.2 Data Sources

The review of the forced shutdowns and power reductions included data from the following sources.

1. *Nuclear Power Plant Operating Experience for 19XX*, for the years 1973–1984.
2. NUREG-0020 series (Gray Books).[20]
3. Annual or semiannual reports from the time of startup through 1977. For 1977 through 1984, monthly operating reports were used because the utility was no longer required to file annual reports. The review of power reductions used primarily the annual, semiannual, and monthly reports.

When LERs describing shutdowns and power reductions were available, their event descriptions gave additional information and helped to support significance screening.

A.3 Significance Screening

Shutdowns and power reductions were evaluated against design basis events (DBEs) found in Chap. 15 of the *Standard Review Plan*[2] (Table A.5). DBEs are those postulated disturbances in process variables or failures and malfunctions of equipment that plants are designed to withstand. Licensees issue the results of their analyses of these events in safety analysis reports.

Generic design-basis initiating events such as "Increase in Heat Removal by the Secondary System" or "Decrease in Reactor Coolant System Flow Rate," were used as primary flags for reviewing the forced shutdowns (and power reductions). Once the generic type of event was identified, the particular initiating event was determined from the details associated with the shutdown. For example, if the reactor shuts down as a result of an increase in heat removal because a feedwater regulator valve failed open, the event falls into the category of generic Type 1 DBEs. Based on the specific initiating event (valve failed open), the event is classified as a 1.2 DBE — "Feedwater System Malfunction that Results in an Increase in Feedwater Flow." Some shutdowns were readily identifiable as specific DBEs, such as the tripping of a main coolant pump, classified as a 3.1 DBE. Once categorized as a DBE, the shutdown was considered significant regardless of the resulting effect on the plant (because a DBE had been initiated).

Loss of flow from one feedwater loop was considered sufficient to qualify as a 2.7 DBE — "loss of normal feedwater flow." The closure of a main steam isolation valve in one loop was considered sufficient to qualify as a 2.4 DBE — "inadvertent closure of main steam isolation valves."

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Those shutdowns that were not DBEs were assigned NOAC categories (Table A.6) to provide more information on the failure or error associated with the shutdown. With these categories, more specific types of errors and failures could be examined through tabular summaries to focus the reviewer's attention on problem areas (safety related or not) that were not revealed by the DBE categories.

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
11/19/1970	16	NA	RO 70-40	MOMENTARY MAIN STEAM LINE HIGH FLOW SIGNAL	B	3	CD	INSTRU	D1.3
11/21/1970	11	NA		REACTOR MODE SWITCH WIGGLING RESULTED IN MAIN STEAM ISOLATION	B	3	CD	INSTRU	D2.1
11/22/1970	2	15		PACKING LEAK ON ISOLATION CONDENSER STEAM SUPPLY VALVE	B	1	CE	VALVEX	N1.1.6
12/05/1970	2	0		ELECTRICAL PRESSURE REG CONTROL OSCILLATION CAUSED SPURIOUS LO LEVEL INDICATION	B	3	HA	INSTRU	D1.3
12/23/1970	24	0	AO 70-08	CRACKED WELD ON MAIN CONDENSER	B	1	HC	HTEXCH	N1.1.6
12/29/1970	23	0	AO 70-09	PRESSURE CONTROL BYPASS VALVE LINKAGE TORN FROM ITS SUPPORTS	B	1	HB	VALVEX	N1.1.9
12/30/1970	1	13		TURBINE TRIP DUE TO HIGH LEVEL IN MOISTURE SEPARATOR DRAIN TANK	B	3	HA	TURBIN	D2.3

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Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1/02/1971	1	40		TURBINE TRIP DUE TO HIGH LEVEL IN MOISTURE SEPARATOR DRAIN TANK	A	3	HA	TURBIN	D2.3
1/02/1971	7	11.5		TURBINE TRIP - HIGH LEVEL IN MOISTURE SEPARATOR DRAIN TANK	A	3	HA	TURBIN	D2.3
1/14/1971	16	64		TURBINE MANUALLY TRIPPED TO FIX CONDENSER LEAK	A	1	HC	HTEXCH	N3.1
1/19/1971	109	0	AO 71-02	REACTOR SHUTDOWN - TURBINE CONTROL VALVE CLOSED	A	1	SF	VALVEX	D2.1
1/25/1971	33	0		REACTOR SHUTDOWN TO REPAIR CORE SPRAY INJECTION VALVES	B	1	SF	VALVEX	N1.0
1/27/1971	85	0		TRAVELING SCREEN DAMAGED CIRCULATING WATER PUMP-DAMAGED SHAFT	B	1	HF	PUMPXX	N1.1.4
2/12/1971	24	0	RS 71-17	SPURIOUS INDICATION OF LOW REACTOR WATER LEVEL TRIP OF ECCS	A	3	CB	INSTRU	N1.1.4
2/21/1971	21	75		TURBINE TRIP - HIGH MOISTURE SEPARATOR LEVEL	A	3	HA	TURBIN	D2.3
3/02/1971	65	16		MAIN STEAM LINE SAFETY VALVE BLOWING STEAM	A	1	HB	VALVEX	D6.1
3/12/1971	5	100		TURBINE TRIP - HIGH MOISTURE SEPARATOR DRAIN TANK LEVEL	A	3	HA	TURBIN	D2.3
4/14/1971	3	0		REPAIR COMMUTATOR RINGS ON M-G SETS	B	1	CB	GENERA	N1.1.4
4/19/1971	6	90		MAIN STEAM LINE LOW PRESSURE TRIP SENSING LINE BROKE	A	3	CC	INSTRU	N2.1
4/21/1971	8	45		TURBINE TRIP - HIGH MOISTURE SEPARATOR DRAIN TANK LEVEL	A	3	HA	TURBIN	D2.3
4/22/1971	1	100		TURBINE TRIP HMSDTL	A	3	HA	TURBIN	D2.3
4/22/1971	1	100		TURBINE TRIP HMSDTL	A	3	HA	TURBIN	D2.3
4/22/1971		100		TURBINE TRIP HMSDTL	A	3	HA	TURBIN	D2.3

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Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
4/22/1971	1	100		TURBINE TRIP HMSDTL	A	3	HA	TURBIN	D2.3
4/22/1971	1	100		TURBINE TRIP HMSDTL	A	3	HA	TURBIN	D2.3
5/01/1971	39	60		REPAIR CONDENSATE TEST LINE	A	1	HH	PIPEXX	N1.1.4
5/12/1971	17	70		REPAIR AIR LEAK IN DRYWELL	A	1	SA	VESSEL	N1.1.4
5/25/1971	7	70	AO 71-11	FEEDWATER CONTROL VALVE CLOSED	A	3	CH	INSTRU	D1.1
5/27/1971	57	80	AO 71-12	TURBINE CONTROL VALVES FAILED SHUT	A	3	HA	VALVEX	D2.3
5/30/1971	12	20		STEAM LEAK IN MAIN STEAM LINE	A	1	CC	PIPEXX	N3.1
6/11/1971	2	100		TURBINE TRIP HMSDTL	A	3	HA	TURBIN	D2.3
6/11/1971	1	100		TURBINE TRIP HMSDTL	A	3	HA	TURBIN	D2.3
6/24/1971	2	100	LTR 7/21/71	TURBINE FULL LOAD REJECT DUE TO LIGHTNING CAUSING LOSS OF 383 LINE	A	3	HA	TURBIN	D2.2
6/25/1971	2	100		TURBINE TRIP DUE TO LIGHTNING CAUSING LOSS OF 383 LINE	A	1	HA	TURBIN	D2.2
6/26/1971	3	0		SPURIOUS IRM TRIP	A	3	IA	INSTRU	N2.4
8/12/1971	4	45		TURBINE TRIP HMSDTL	A	3	HA	TURBIN	D2.3
8/29/1971	7	45		TRAVELING SCREEN FAILURE CAUSED LOSS OF CIRC WATER PUMPS & TURBINE TRIP	A	3	HF	PUMPXX	N1.1
8/30/1971	168	0		MAIN CONDENSER LOW VACUUM TRIP	A	3	HC	HTEXCH	D2.5
9/23/1971	134	80		850 PSI LOW PRESSURE TRIP	A	3	CC	INSTRU	N1.1.4
9/29/1971	83	0	AO 71-19	TURBINE CONTROL VALVE MALFUNCTION	A	3	HA	VALVEX	D2.3
10/03/1971	60	0		TURBINE CONTROL VALVE MALFUNCTION	A	3	HA	VALVEX	D2.3
10/10/1971	248	0	AO 71-20	TURBINE CONTROL VALVE MALFUNCTION	A	3	HA	VALVEX	D2.3

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ MSIC(M) Event Category
10/22/1971	20	0		FAILURE OF AUTO PRESSURE RELIEF VALVE TO SEAT DUE TO SCORED PILOT VALVE DISC	A	3	CC	VALVEX	M1.1.4
10/24/1971	18	0		APR BELLOWS LEAK	A	3	CC	VALVEX	M1.1.4
12/11/1971	4	100		INADVERTENT MAKE-UP OF REACTOR PRESSURE SWITCH	G	3	CC	INSTRU	M6.1
12/11/1971	4	100		INSTRUMENT ERROR ON MAIN STEAM LINE FLOW DETECTORS	A	3	CC	INSTRU	M1.1.4
12/12/1971	4	100	AO 71-27	REACTOR PRESSURE SWITCH INADVERTENTLY TRIPPED	G	3	CC	INSTRU	M6.1
12/15/1971	3	30		TURBINE TRIP - HIGH MOISTURE SEPARATOR LEVEL	A	3	HA	TURBIN	D2.3
12/20/1971	57	100		FAULTY ISOLATION CONDENSER RETURN VALVE	A	1	CE	VALVEX	M1.1.4

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
2/04/1972	169	70		TURBINE STOP VALVE TESTING INDUCED PRESS OSCILLATIONS RESULTING IN TURBINE TRIP	A	3	HA	VALVEX	D2.3
2/11/1972	83	0		LEAKY MAIN STEAM LINE GASKETS	A	1	CC	PIPEXX	N3.1
2/14/1972	129	30		IMPROPER RESPONSE FROM MAIN STEAM LINE VENTURI DIFFERENTIAL PRESS CELLS	A	1	CC	INSTRU	N1.1.6
2/23/1972	168	100	AO 72-08	DEGRADED MAIN STEAM LINE VENTURI	A	1	CC	INSTRU	N1.1.6
3/09/1972	62	20		FAULTY OPERATION OF THRUST BEARING WEAR DETECTOR INDUCED TURBINE TRIP	A	3	HA	TURBIN	D2.3
3/12/1972	2	30		VOID COLLAPSE FROM COLD FEEDWATER INCREASE IN FLOW	A	3	CH	PUMPXX	D1.2
8/18/1972	5	100		TESTING OF THRUST BEARING WEAR DETECTOR TRIPPED TURBINE	A	3	HA	INSTRU	D2.3
8/29/1972	27	100		DRYWELL FLOOR DRAIN SUMP LEAKAGE	A	1	SA	VESSEL	N1.1.6

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(M) Event Category
3/03/1973	7	50		POWER REDUCTION - LEAK IN MAIN CONDENSER	A	5	HC	HTEXCH	M1.1.4
3/06/1973	13	50	AO 74-01	EXCESSIVE DRYWELL LEAKAGE FROM STEM PACKING OF REACTOR RECIRC EQUALIZER VALVE	A	1	SA	VALVEX	M10
3/06/1973	53	0		CONDENSATE BOOSTER PUMP NOT STARTED IN TIME-LOW WATER LEVEL	G	3	CH	PUMPXX	D3.7
3/11/1973	31	40		REPAIRED MAIN STEAM ISOLATION POSITION INDICATION SWITCH	A	1	CD	VALVEX	M2.4
3/13/1973	6	75		LOW LUBE-OIL PRESSURE ALARM ON RECIRC PUMP MOTOR	A	1	CA	MOTORX	M1.1.4
3/14/1973	83	80	RO 73-02	BLOWN FUSE ON CRD SCRAM SOLENOID SCRAMMED GROUP II CONTROL RODS	A	3	RB	CKTBRK	M1.1.4
3/19/1973	40	50		LOW LUBE-OIL PRESS ALARM REACTOR PUMP	A	1	CA	PUMPXX	M1.1.4
4/18/1973	2152	10		REPLACED FEEDWATER SPARGER	A	1	CH	PIPEXX	M1.1.4
7/14/1973	64	0		LEAK ON VENT LINE FOR RECIRCULATION PUMP DISCHARGE	A	1	CA	PIPEXX	M1.1.8
7/16/1973	236	0		EXAMINE FOR INVERTED CONTROL ROD INTERNALS	D	1	RB	CONROD	M8.3
7/30/1973	12	60		REACTOR VESSEL WATER LEVEL TRANSMITTER FAILURE	A	3	CB	INSTRU	M2.1
8/10/1973	14	76		REACTOR VESSEL WATER LEVEL TRANSMITTER LEVEL MALFUNCTION	A	3	CB	INSTRU	M2.1
8/10/1973	4	0		HIGH REACTOR WATER LEVEL DUE TO STARTING FEEDWATER PUMP	G	3	CB	PUMPXX	D1.2

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9/19/1973	36	0		LEAKING INSTRUMENT TAP IN FEEDWATER LINE	A	1	CH	PIPEXX	N1.1.4
9/20/1973	25	0		LEAKING AUTOMATIC PRESSURE RELIEF VALVE	A	1	CC	VALVEX	N1.1.4
9/21/1973	11	50		FAULT IN EPR CONTROLS OPENED TURBINE BYPASS VALVES DROPPING REACTOR PRESSURE	A	3	CC	INSTRU	D1.3
10/06/1973	16	67		RECIRC PUMP MOTOR FAILED	A	1	CA	MOTORX	N1.1.4
10/13/1973	76			FAULT IN MODE SWITCH CAUSED A SCRAM	A	3	CB	INSTRU	N2.1
10/14/1973	20	60		TESTED RECIRC PUMP MOTOR	A	1	CA	MOTORX	N1.1.4
10/28/1973	42	67		OPENED AND TESTED RECIRC LOOP CROSS-TIE VALVES	A	1	CA	VALVEX	N2.4
12/07/1973	5	80		PERSON BUMPED LEVEL INSTRUMENT RACK	G	3	CB	INSTRU	N6.3
12/30/1973	16	0	AO 73-42	ISOLATION CONDENSER FLANGE LEAK	A	1	CE	PIPEXX	N1.1.4

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/NSIC(N) Event Category
3/02/1974	4	50		POWER REDUCTION - SUSPECTED LEAK IN MAIN CONDENSER	A	5	HC	HTEXCH	N1.1.4
6/11/1974	7	65		RECIRC PUMP SPEED CONTROL FAULT	A	3	CB	INSTRU	N1.1.4
11/03/1974	15	35		TURBINE TRIP CAUSED BY MAINTENANCE ON FEEDWATER TRANSMITTER	A	3	HA	INSTRU	D2.3
11/04/1974	5	40		APRM HIGH FLUX DUE TO PRESSURE OSCILLATIONS	A	3	CC	INSTRU	N1.1.4
11/04/1974	9	35	AO 74-09	MSIV MALFUNCTION DUE TO MOISTURE IN THE SLIDE VALVE THAT CONTROLS VALVE ACTION	A	3	CD	VALVEX	D2.4
11/15/1974	8	0	AO 74-10	POWER REDUCTION - MSIV FAILED TO CLOSE	A	5	CC	VALVEX	N1.1.4
11/18/1974	15	0		POWER REDUCTION - MAIN GENERATOR EXCITER GROUND FAULT	A	5	HB	GENERA	N1.1.4
12/16/1974	8	97		BROKEN STEM - FEEDWATER CONTROL VALVE PREVENTED FLOW OF FEEDWATER	A	3	CH	VALVEX	D2.7
12/27/1974	1	15		POWER REDUCTION - TURBINE TRIP DUE TO HIGH LEVEL IN MOISTURE SEPARATOR	A	5	HA	TURBIN	D2.3
12/27/1974	34	95		REPAIR MAIN FEEDWATER CONTROL VALVE	A	1	CH	VALVEX	N1.1.4
12/29/1974	3	10		POWER REDUCTION -TURBINE TRIP DUE TO HIGH LEVEL IN MOISTURE SEPARATOR	A	5	HA	TURBIN	D2.3
12/29/1974	2	10		POWER REDUCTION - TURBINE TRIP DUE TO HIGH LEVEL IN MOISTURE SEPARATOR	A	5	HA	TURBIN	D2.3

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
2/15/1975	9	20		POWER REDUCTION - DRYWELL ENTRY MADE TO PERFORM MAINTENANCE ON TRIP INDEX	A	5	RC	INSTRU	N2.1
3/11/1975	87	60		BLOWN VALVE STUFFING BOX - LPCI SYSTEM	A	1	SF	VALVEX	N1.1.4
5/20/1975	55	100	AO 75-09	PRESSURE RELIEF VALVE FAILED TO SEAT	A	2	CC	VALVEX	N1.1.4
6/20/1975	35	15		SERVICE WATER PUMP REPAIRS	A	1	WA	PUMPXX	N1.1.4
8/13/1975	16	80		POWER REDUCTION - ARCING ON B-PHASE DISCONNECT	A	5	EB	CKTBRK	N1.1.4
8/18/1975	5	96		POWER REDUCTION - APR'S FAILED TO MEET TECH SPECS	B	5	CC	VALVEX	N1.1.4
8/30/1975	8	0		PRESSURE REG TRANSIENT CAUSED APRM SCRAM DUE TO PLUGGED MOOG VALVE FILTER	H	3	CC	FILTER	N1.1.4
9/12/1975	451	94		TRANSFORMER INSULATION BREAKDOWN	B	1	EB	TRANSF	N1.1.4
10/25/1975	15	2		INSTALLING INSULATING BOLTS ON MAIN TRANSFORMER	H	1	EB	TRANSF	N1.1.4
10/27/1975	19	60		MAINTENANCE ON TRANSVERSING INCORE PROBE SYSTEM	A	1	RC	INSTRU	N1.1.4
11/13/1975	223	90		CRACK IN JET PUMP BREAK DETECTION SENSING LINE	A&B	1	CC	INSTRU	N1.1.4
11/23/1975	9	0		OSCILLATIONS IN PRESSURE REGULATOR DUE TO DIRT IN SENSING LINES	A	3	CC	INSTRU	N1.1.4
11/26/1975	8	60		PRESSURE SPIKE OCCURRED WHILE SWITCHING TO MECH PRESSURE REGULATOR	A	3	CC	INSTRU	N1.1.4
12/11/1975	66	90		INSTALLED MISSING PART ON MAIN TRANSFORMER	A&B	1	EB	TRANSF	N5.1

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Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
2/12/1976	42	100		ARCING ACROSS HIGH VOLTAGE BUSING ON MAIN TRANSFORMER-TRIPPED GENERATOR	A	3	EB	TRANSF	N1.1.4
3/08/1976	85	100	RO 76-10	INOPERABILITY OF GAS TURBINE GENERATOR DUE TO GOVERNOR OUT OF ADJUSTMENT	A&B	1	EF	TURBIN	N1.1.4
3/15/1976	132	20		INOPERABILITY OF GAS TURBINE-REPLACED ELECTRONIC GOVERNOR	A&B	1	EF	TURBIN	N1.1.4
7/16/1976	64	90		REPAIRED MOTOR OPERATOR OF ISOLATION CONDENSER ISOLATION VALVE	A	1	CE	VALVOP	N1.1.4
8/10/1976	105	95		HIGH WINDS DEPOSITED SALT ON MAIN TRANSFORMER INSULATORS - ARCING	H	3	EB	TRANSF	N9.2
8/10/1976	100	95	RO 76-29	PROBLEMS WITH SPEED CONTROL OF GAS TURBINE GENERATOR - OUTAGE EXTENSION	A	1	EE	TURBIN	N1.1.4
8/22/1976	0	65		POWER REDUCTION - ADJUST CONTROL ROD PATTERN	H	5	RB	CONROD	N1.1
12/01/1976	45	100		PROBLEMS WITH MAIN TURBINE GENERATOR PRESSURE REGULATOR CAUSING IT TO OPEN	A	1	HA	INSTRU	N1.1.4
12/17/1976	51	100	RO 76-42	MALFUNCTION OF ISOLATION CONDENSER ISO VALVE, CLEANUP ISOLATION VALVE	A	1	CE	VALVOP	N1.1.4

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Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ MSIC(M) Event Category
1/03/1977	89	100		MALFUNCTION OF MAIN GENERATOR ELECTRIC PRESSURE REG DUE TO PLUGGED LINE	A	3	HB	INSTRU	M2.1
1/26/1977	13	100	RO 77-05	INCREASING COOLANT CONDUCTIVITY DUE TO DEMINERALIZER MALFUNCTION	A	2	CG	DEMINX	M1.1.4
3/06/1977	36	100		REPAIR OF SMALL STEAM LEAK ON MAIN LINE DRAIN LINE TO MAIN CONDENSER	A	1	HB	PIPEXX	M1.1.4
4/07/1977	9	100		WHILE DOING REACTOR WATER LEVEL SURVEILLANCE, INADVERTENT REACTOR SCRAM OCCURRED	A	3	IA	VALVEX	M2.4
4/23/1977	0	100		POWER REDUCTION - REPAIR STEAM LEAK ON EXTRACTION NON-RETURN VALVE	A	5	HA	VALVEX	M1.1.4
5/14/1977	11	100		STEAM LEAK ON AN EXTRACTION NON-RETURN VALVE	A	3	HA	VALVEX	M1.1.4
6/13/1977	8	0		FAULTY TEST SOLENOID PREVENTED MS VALVE FROM RETURNING TO OPEN POSITION	A	3	HB	INSTRU	M2.1
6/14/1977	132	0		MECHANICAL PRESSURE REGULATOR SWING TRIPPED TURBINE	A	2	HB	CKTBRK	M2.4
6/19/1977	6	100		MECHANICAL PRESSURE REGULATOR DID NOT TAKE CONTROL-BYPASS VALVES FAILED OPEN	A	3	HB	CKTBRK	M2.4
7/12/1977	10	100		BENT ACTUATOR ON MAIN STEAM ISOLATION VALVE ALLOWED VALVE TO CLOSE	A	3	CU	CKTBRK	D2.4
7/22/1977	37	100		FALSE SIGNAL TRIPPED BREAKER ON LUBE OIL PUMP FOR RECIRC MG SET	A	3	CB	INSTRU	M2.4
8/06/1977	37	100	RO 77-24	LOSS OF PLANT AIR DUE TO LOSS OF COOLING WATER TO AIR COMPRESSORS	A	3	PA	BLOWER	M1.1.4

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8/27/1977	0	100		POWER REDUCTION - PLUG TUBES IN MAIN CONDENSERS	B	5	HC	HTEXCH	N1.1.4
9/21/1977	0	78		POWER REDUCTION - CONDENSER TUBE MAINTENANCE	B	5	HC	HTEXCH	N1.1.4
11/22/1977	66	100		LEAK IN FEEDWATER HEATER	A&B	1	CH	HTEXCH	N1.1.4
11/29/1977	55	58		AUTOMATIC PRESSURE RELIEF VALVE LIFTED PREMATURELY	A&B	2	CC	VALVEX	D6.1
12/13/1977	263	99	RO 77-40	MANUAL SCRAM IN RESPONSE TO A SECOND HYDROGEN EXPLOSION IN OFFGAS STACK	A	2	MB	XXXXXX	N1.1.4

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DER(D)/ NSIC(N) Event Category
1/25/1978	0	75		REDUCED POWER FOR MAIN CONDENSER MAINTENANCE	A	5	HC	HTEXCH	N1.1.6
1/31/1978	18	90		STEAM LEAK ON 2 INCH STEAM LINE	A	1	CC	PIPEXX	N1.1.6
5/19/1978	22	100		MALFUNCTION OF LEVEL CONTROL SYSTEM FOR MOISTURE SEPARATOR TRIPPED TURBINE	A	3	CC	INSTRU	D2.3
5/29/1978	16	100		BROKEN AIR SUPPLY TUBE TO MOISTURE SEPARATOR LEVEL CONTROLLER TRIPPED TURBINE	A	3	HA	PIPEXX	D2.3
6/10/1978	0	100		POWER REDUCTION - PLUG MAIN CONDENSER TUBES	A	5	HC	HTEXCH	N1.1.6
7/03/1978	0	90		REDUCED POWER TO PLUG MAIN CONDENSER TUBING	A	5	HC	HTEXCH	N1.1.6
7/14/1978	100	100		REPLACED CONTMT ISO VALVE CABLE SPLICES WITH ONES ENVIRONMENTALLY QUALIFIED	B	1	ED	ELECON	N10
7/20/1978	1	100		MALFUNCTION OF MOISTURE SEPARATOR DRAIN TANK LEVEL CONTROLLERS TRIPPED TURBINE	A	9	HB	INSTRU	D2.3
7/25/1978	0	80		REDUCED POWER TO PLUG MAIN CONDENSER TUBING	A	5	HC	HTEXCH	N1.1.6
7/26/1978	0	80		REDUCED POWER TO PLUG MAIN CONDENSER TUBING	A	5	HC	HTEXCH	N1.1.6
7/27/1978	0	80		REDUCED POWER TO PLUG MAIN CONDENSER TUBING	A	5	HC	HTEXCH	N1.1.6
7/29/1978	0	97		REDUCED POWER TO PLUG MAIN CONDENSER TUBING	A	5	HC	HTEXCH	N1.1.6
8/18/1978	0	95		REDUCED POWER TO PLUG MAIN CONDENSER TUBING	A	5	HC	HTEXCH	N1.1.6

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8/20/1978	0	40		REDUCED POWER TO PLUG MAIN CONDENSER TUBING	A	5	HC	HTEXCH	N1.1.4
9/04/1978	0	70		REDUCED POWER FOR MAIN CONDENSER MAINTENANCE	A	5	HC	HTEXCH	N1.1.4
12/12/1978	44	100		MAIN STEAM LINE FLOW INSTRUMENTATION CHECK OUT	A	3	IA	INSTRU	N2.4

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1/06/1979	269	100	LER 79-01	STRESS CORROSION CRACKING OF CLEAN-UP RETURN LINE	A	1	CG	PIPEXX	N1.1.4
1/19/1979	30	70		CHANGE AUTOMATIC PRESSURE RELIEF VALVE TOPWORKS	A	1	SF	VALVOP	N1.1.4
1/22/1979	0	97		REDUCED POWER FOR MAIN CONDENSER MAINTENANCE	B	5	HC	HTEXCH	N1.1.4
2/26/1979	33	100	LER 79-05	SAFETY RELIEF VALVE LIFTED PREMATURELY AND FAILED TO RESEAT	A	2	CC	VALVEX	D6.1
3/10/1979	0	97		REDUCED POWER FOR MAIN CONDENSER MAINTENANCE	B	5	HC	HTEXCH	N1.1.4
3/17/1979	10	100		MSIV POSITION INDICATING PROBLEMS	A	9	CD	INSTRU	N2.4
6/28/1979	0	15		TURBINE TRIP DUE TO FEEDWATER REGULATING VALVE LOCK-UP	A	3	CH	VALVEX	D2.3
7/02/1979	30	90		LOSS OF BOTH PLANT AIR COMPRESSORS	A	3	PA	BLOWER	N1.1.4
8/15/1979	0	70		REDUCED POWER FOR MAIN CONDENSER MAINTENANCE	B	5	HC	HTEXCH	N1.1.4
12/19/1979	52	100		MAIN GENERATOR LOSS OF EXCITATION	A	3	HA	GENERA	D2.3

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1/05/1980	648	100		REDUCED POWER TO 40% DUE TO ISOLATION CONDENSER OUT OF SERVICE	A	5	CB	HTEXCH	N1.1.3
6/25/1980	13	20		ELECTRIC PRESSURE REGULATOR MALFUNCTION INDUCED APRM SCRAM	A	3	CC	INSTRU	D2.1

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
4/19/1981	3	0		LOW PWR ASCENSION TURBINE TRIP ON MOISTURE SEPARATOR HI LEVEL-NO CHANGE ON POWER	A	9	HA	TURBIN	D2.3
4/21/1981	1372		LER 81-004	MANUAL TRIP ON HI VIBRATE-REACTOR SCRAM ON HI MAIN CONDENSER CONDUCTIVITY	A	2	HC	TURBIN	D2.3
6/15/1981	13	0		REACTOR MODE SWITCH FAILURE	A	9	IA	INSTRU	N2.0
7/06/1981				POWER REDUCTION - PROCESS COMPUTER FAILURE	A	5	IE	INSTRU	N2.0
7/12/1981	26			FEEDWATER REGULATION VALVE CLOSURE	A	3	CH	VALVEX	D2.7
7/18/1981				PWR REDUCTION-CONDENSATE BOOSTER PMP REPAIR/SERVICE WATER CROSS-OVER VLV REPAIR	B	5	HA	VALVEX	N1.1.4
8/08/1981	35			REACTOR RECIRC PUMP 'A' TRIPPED ON GENERATOR OVERLOAD WITH 'B' PUMP OFF-LINE	A	2	CB	GENERA	D3.1
8/10/1981	52		LER 81-023	UNIT SCRAM ON HI RISK TEST-SCRAM'D CHANL NOT RESET PRIOR TO TESTING ALT CHANLS	G	3	IA	INSTRU	N6.1
9/05/1981	55			SHUTDOWN TO REBALANCE TURBINE	B	1	HA	TURBIN	N1.1.4
9/14/1981	42			SPURIOUS ATWS SYS ISO PWR SURGE TO ATWS SYS-SCRAM AIR HEADER TO DEPRESSURIZER	A	3	IA	INSTRU	N2.0
12/03/1981	0	100		POWER REDUCTION - FIND AN REPAIR MAIN CONDENSER LEAKS	A	5	HC	HTEXCH	N3.1
12/28/1981	43			COND PMP TRIP DUE TO DISCREPANCY BET HOWELL LEVEL TRANSMITTER & ACTUAL LEVEL	A	3	CH	INSTRU	N2.0

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Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ HSIC(H) Event Category
1/28/1982	0.0	91		STEAM LEAK IN STEAM TUNNEL	B	5	CC	PIPEXX	H3.1
2/12/1982	30.0	91		'A' FDWTR REG VALVE CYCLED AND CAUSED SCRAM	A	3	CH	VALVOP	H2.1
4/03/1982	0	91		REPAIR LEAKING MAIN CONDENSER TUBES & CHANGE CR PATTERN	B	5	HC	HTEXCH	H1.1.4
4/10/1982	0	91		LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	H1.1.4
4/13/1982	17.0			RECIRC PUMP TRIP FROM ATWSS WHILE TRACING DC GROUND	G	2	HC	HTEXCH	H6.3
4/19/1982	0			LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	H1.1.4
4/25/1982	0			LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	H1.1.4
6/26/1982	0			MG SET REBRUSHING & CR PATTERN ADJUST	B	5	RC	CONROD	H1.1
7/27/1982	0			FIND AND PLUG LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	H1.1.4
7/31/1982	53.1			GENERATOR OUT-OF-STEP RELAY CAUSED TRIP & LOAD REJECT PLUS ATWSS SCRAM	H	3	HA	GENERA	H2.1

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DRE(D)/ NSIC(N) Event Category
1/24/1983	29.9			MOISTURE CAUSED STEAM TUNNEL HIGH TEMP ALARM SWITCH TO GROUND	A	3	IE	INSTRU	N2.1
3/24/1983	130.8			IDENTIFY & REPAIR DRYWELL LEAKAGE. F/W TRANSIENT LATER CAUSED SCRAM	D	1	SA	PIPEXX	N3.1
3/31/1983	12.2			HI MOISTURE SEP LEVEL PLUS TURB TRIP CAUSED RX SCRAM	H	3	HA	TURBIN	D2.3
4/05/1983	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.4
4/29/1983	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.4
5/19/1983	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.4
6/07/1983	33.2			TURBINE TRIP ON HI RX WATER LEVEL	H	3	HA	TURBIN	D1.2
6/10/1983	90.7		83-24	TRIP GAS TURBINE	A	1	EE	TURBIN	N1.1.4
8/25/1983	16.4			SCRAM ON LOW AIR PRESS. WHEN INST. AIR COMPRESSOR TRIPPED	A	3	IP	BLOWER	N1.1.4
9/04/1983	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.4
10/05/1983	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.4
10/24/1983	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.4
11/27/1983	62.0			REPAIR LEAKING 'A' RECIRC PUMP SEAL	A	1	CB	PUMPXX	N3.1
12/21/1983	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.4

Table A.1 Forced Shutdowns and Power Reductions for Millstone 1 (Continued)

Date	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1/16/1984	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.0
7/21/1984	0			ADJUST CONTROL ROD PATTERN	H	5	RC	CONROD	N1.1
8/02/1984	41.5			DRYWELL ENTRY TO FIND & FIX LEAK IN RECIRC SYS RISER INST VALVE	B	1	CB	VALVEX	N3.1
9/17/1984	0			REBRUSH 'A' RECIRC MG SET	B	5	CB	MOTORX	N1.1.0
10/20/1984	0			FIND & REPAIR LEAKING MAIN CONDENSER TUBES	B	5	HC	HTEXCH	N1.1.0
12/05/1984	0			REPAIR STICKING 'B' FEEDWATER REG VALVE	B	5	CH	VALVEX	N1.1.0

Table A.2. Codes for the causes of forced shutdowns power reductions and the methods of shutdown

	Causes
A	Equipment failure
B	Maintenance or testing
C	Refueling
D	Regulatory restriction
E	Operator training and license exams
F	Administrative
G	Operational error
H	Other
	Methods
1	Manual
2	Manual scram
3	Automatic scram
4	Continuation
5	Load reduction
9	Other

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Table A.3. Systems involved with forced shutdowns and power reductions

System	Code
Reactor	RX
Reactor vessel internals	RA
Reactivity control systems	RB
Reactor core	RC
Reactor coolant and connected systems	CX
Reactor vessels and appurtenances	CA
Coolant recirculation systems and controls	CB
Main steam systems and controls	CC
Main steam isolation systems and controls	CD
Reactor core isolation cooling systems and controls	CE
Residual heat removal systems and controls	CF
Reactor coolant cleanup systems and controls	CG
Feedwater systems and controls	CH
Reactor coolant pressure boundary leakage detection systems	CI
Other coolant subsystems and their controls	CJ
Engineered safety features	SX
Reactor containment systems	SA
Containment heat removal systems and controls	SB
Containment air purification and cleanup systems and controls	SC
Containment isolation systems and controls	SD
Containment combustible control systems and controls	SE
Emergency core cooling systems and controls	SF
Core reflooding	SF-A
Low-pressure safety injection system and controls	SF-B
High-pressure safety injection system and controls	SF-C
Core spray system and controls	SF-D
Control room habitability systems and controls	SG
Other engineered safety feature systems and their controls	SH
Containment purge system and controls	SH-A
Containment spray system and controls	SH-B
Auxiliary feedwater system and controls	SH-C
Standby gas treatment systems and controls	SH-D
Instrumentation and controls	IX
Reactor trip systems	IA
Engineered safety feature instrument systems	IB
Systems required for safe shutdown	IC
Safety-related display instrumentation	ID
Other instrument systems required for safety	IE
Other instrument systems not required for safety	IF

Table A.3 (continued)

System	Code
Electric power systems	EX
Offsite power systems and controls	EA
AC onsite power systems and controls	EB
DC onsite power systems and controls	EC
Onsite power systems and controls (composite ac and dc)	ED
Emergency generator systems and controls	EE
Emergency lighting systems and controls	EF
Other electric power systems and controls	EG
Fuel storage handling systems	FX
New fuel storage facilities	FA
Spent-fuel storage facilities	FB
Spent-fuel pool cooling and cleanup systems and controls	FC
Fuel handling systems	FD
Auxiliary water systems	WX
Station service water systems and controls	WA
Cooling systems for reactor auxiliaries and controls	WB
Demineralized water makeup systems and controls	WC
Potable and sanitary water systems and controls	WD
Ultimate heat sink facilities	WE
Condensate storage facilities	WF
Other auxiliary water systems and controls	WG
Auxiliary process systems	PX
Compressed air systems and controls	PA
Process sampling systems	PB
Chemical, volume control, and liquid poison systems and controls	PC
Failed-fuel detection systems	PD
Other auxiliary process systems and controls	PE
Other auxiliary systems	AX
Air conditioning, heating, cooling, and ventilation systems and controls	AA
Fire protection systems and controls	AB
Communication systems	AC
Other auxiliary systems and controls	AD
Steam and power conversion systems	HX
Turbine-generators and controls	HA
Main steam supply systems and controls (other than CC)	HB
Main condenser systems and controls	HC
Turbine gland sealing systems and controls	HD

Table A.3 (continued)

System	Code
Turbine bypass systems and controls	HE
Circulating water systems and controls	HF
Condensate cleanup systems and controls	HG
Condensate and feedwater systems and controls (other than CH)	HH
Steam generator blowdown systems and controls	HI
Other features of steam and power conversion systems (not included elsewhere)	HJ
Radioactive waste management systems	MX
Liquid radioactive waste management systems	MA
Gaseous radioactive waste management systems	MB
Process and effluent radiological monitoring systems	MC
Solid radioactive waste management systems	MD
Radiation protection systems	BX
Area monitoring systems	BA
Airborne radioactivity monitoring systems	BB

Table A.4. Components involved with forced shutdowns and power reductions

Component type	Including
Accumulators	Scram accumulators Safety injection tanks
Air dryers	
Annunciator modules	Alarms Bells Buzzers Claxons Horns Gongs Sirens
Batteries and chargers	Chargers Dry cells Wet cells Storage cells
Blowers	Compressors Gas circulators Fans Ventilators
Circuit closers/interruptors	Circuit breakers Contactors Controllers Starters Switches (other than sensors) Switchgear
Control rods	Poison curtains
Control rod drive mechanisms	
Demineralizers	Ion exchangers
Electrical conductors	Bus Cable Wire
Engines, internal combustion	Butane engines Diesel engines Gasoline engines Natural gas engines Propane engines
Filters	Strainers Screens
Fuel elements	

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Table A.4 (continued)

Component type	Including
Generators	Inverters
Heaters, electric	
Heat exchangers	Condensers Coolers Evaporators Regenerative heat exchangers Steam generators Fan coil units
Instrumentation and controls	
Mechanical function units	Mechanical controllers Governors Gear boxes Varidrives Couplings
Motors	Electric motors Hydraulic motors Pneumatic (air) motors Servo motors
Penetrations, primary containment air locks	
Pipes, fittings	
Pumps	
Recombiners	
Relays	
Shock suppressors and supports	
Transformers	
Turbines	Steam turbines Gas turbines Hydro turbines
Valves	Valves Dampers
Valve operators	
Vessels, pressure	Containment vessels Dry wells Pressure suppression Pressurizers Reactor vessels

Table A.5. Initiating event descriptions for DBEs as listed in Chap. 15, *Standard Review Plan* (Revision 3)

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1. Increase in heat removal by the secondary system
    - 1.1 Feedwater system malfunction that results in a decrease in feedwater temperature
    - 1.2 Feedwater system malfunction that results in an increase in feedwater flow
    - 1.3 Steam pressure regulator malfunction or failure that results in increasing steam flow
    - 1.4 Inadvertent opening of a steam generator relief or safety valve
    - 1.5 Spectrum of steam system piping failures inside and outside of containment in a pressurized-water reactor (PWR)
    - 1.6 Startup of idle recirculation pump[a]
    - 1.7 Inadvertent opening of bypass resulting in increase in steam flow[a]

2. Decrease in heat removal by the secondary system
    - 2.1 Steam pressure regulator malfunction or failure that results in decreasing steam flow
    - 2.2 Loss of external electric load
    - 2.3 Turbine trip (stop valve closure)
    - 2.4 Inadvertent closure of main steam isolation valves
    - 2.5 Loss of condenser vacuum
    - 2.6 Coincident loss of onsite and external (offsite) ac power to the station
    - 2.7 Loss of normal feedwater flow
    - 2.8 Feedwater piping break
    - 2.9 Feedwater system malfunctions that result in an increase in feedwater temperature[a]

3. Decrease in reactor coolant system flow rate
    - 3.1 Single and multiple reactor coolant pump trips
    - 3.2 Boiling-water reactor (BWR) recirculation loop controller malfunction that results in decreasing flow rate
    - 3.3 Reactor coolant pump shaft seizure
    - 3.4 Reactor coolant pump shaft break

4. Reactivity and power distribution anomalies
    - 4.1 Uncontrolled control rod assembly withdrawal from a subcritical or low-power start-up condition (assuming the most unfavorable reactivity conditions of the core and reactor coolant system), including control rod or temporary control device removal error during refueling
    - 4.2 Uncontrolled control rod assembly withdrawal at the particular power level (assuming the most unfavorable reactivity conditions of the core and reactor coolant system) that yields the most severe results (low power to full power)
    - 4.3 Control rod maloperation (system malfunction or operator error), including maloperation of part length control rods

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A.5 (continued)

4.4 Start-up of an inactive reactor coolant loop or recirculating loop at an incorrect temperature
4.5 A malfunction or failure of the flow controller in a BWR loop that results in an increased reactor coolant flow rate
4.6 Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant of a PWR
4.7 Inadvertent loading and operation of a fuel assembly in an improper position
4.8 Spectrum of rod ejection accidents in a PWR
4.9 Spectrum of rod drop accidents in a BWR

5. Increase in reactor coolant inventory

5.1 Inadvertent operation of emergency core cooling system during power operation.
5.2 Chemical and volume control system malfunction (or operator error) that increases reactor coolant inventory
5.3 A number of BWR transients, including items 1.2 and 2.1—2.6

6. Decrease in reactor coolant inventory

6.1 Inadvertent opening of a pressurizer safety valve in either a PWR or a BWR
6.2 Break in instrument line or other lines from reactor coolant pressure boundary that penetrate containment
6.3 Steam generator tube failure
6.4 Spectrum of BWR steam system piping failures outside of containment
6.5 Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary, including steam line breaks inside of containment in a BWR
6.6 A number of BWR transients, including items 1.3, 2.7, and 2.8

7. Radioactive release from a subsystem or component

7.1 Radioactive gas waste system leak or failure
7.2 Radioactive liquid waste system leak or failure
7.3 Postulated radioactive releases due to liquid tank failures
7.4 Design basis fuel handling accidents in the containment and spent fuel storage buildings
7.5 Spent fuel cask drop accidents

8. Anticipated transients without scram

8.1 Inadvertent control rod withdrawal
8.2 Loss of feedwater
8.3 Loss of ac power
8.4 Loss of electrical load
8.5 Loss of condenser vacuum
8.6 Turbine trip
8.7 Closure of main steam line isolation valves

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[a] These initiating events were added for BWRs to be more specific than DBE events 5.3 and 6.6.

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A.6. NOAC event categories for non-DBE shutdowns

- N 1.0 Equipment failure
  - N 1.1 Failure on demand under operating conditions
    - N 1.1.1 Design error
    - N 1.1.2 Fabrication error
    - N 1.1.3 Installation error
    - N 1.1.4 End of design life/inherent failure/random failure
  - N 1.2 Failure on demand under test conditions
    - N 1.2.1 Design error
    - N 1.2.2 Fabrication error
    - N 1.2.3 Installation error
    - N 1.2.4 End of design life/inherent failure/random failure
- N 2.0 Instrumentation and control anomalies
  - N 2.1 Hardware failure
  - N 2.2 Power supply problem
  - N 2.3 Setpoint drift
  - N 2.4 Spurious signal
  - N 2.5 Design inadequacy (system required to function outside design specifications
- N 3.0 Non-DBE reductions in coolant inventory (leaks)
  - N 3.1 In primary system
  - N 3.2 In secondary system and auxiliaries
- N 4.0 Fuel/cladding failure (densification, swelling, failed fuel elements as indicated by elevated coolant activity)
- N 5.0 Maintenance error
  - N 5.1 Failure to repair component/equipment/system
  - N 5.2 Calibration error
- N 6.0 Operator error
  - N 6.1 Incorrect action (based on correct understanding on the part of the operator and proper procedures, the operator turned the wrong switch or valve — incorrect action)
  - N 6.2 Action on misunderstanding (based on proper procedures and improper understanding or misinterpretation on the operator's part of what was to be done — incorrect action)
  - N 6.3 Inadvertent action (purpose and action not related, for example, bumping against a switch or instrument cabinet)
- N 7.0 Procedural/administrative error (incorrect operating or testing procedures, incorrect analysis of an event — failure to consider certain conditions in analysis)

Table A.6 (continued)

- N 8.0 Regulatory restriction
  - N 8.1 Notice of generic event
  - N 8.2 Notice of violation
  - N 8.3 Backfit/reanalysis
- N 9.0 External events
  - N 9.1 Human induced (sabotage, plane crashes into transformer)
  - N 9.2 Environment induced (tornado, severe weather, floods, earthquake)
- N 10.0 Environmental operating constraint as set forth in Technical Specifications

APPENDIX B

REVIEW OF REPORTABLE EVENTS

This appendix presents the data for reportable events in tabular form and lists information sources. It describes how the information was encoded and how significance screening criteria were applied.

B.1 Scope

This study reviewed operating events reported in LERs and LER predessors [e.g., AORs, unusual events reports, reportable occurrences (ROs)]. Data on these types of events were retrieved from the NOAC data files. Any documents that contained LER-type information (such as equipment failures or abnormal events) were included to obtain a total picture of the unit's equipment failure history. Primarily, this involved various types of operating reports and general correspondence.

The reportable event table (Table B.1) contains the following information for each reportable event reviewed:

1. LER number or other means of identification of report type,
2. NSIC accession number (a unique identification number assigned to each document entered into the computer file),
3. date of the event,
4. date of the report or letter transmitting the event description,
5. status of the plant at the time of the occurrence (Table B.2),
6. system involved with the reportable event (Table B.3),
7. type of equipment involved with the reportable event (Table B.4),
8. type of instrument involved with the reportable event (Table B.4),
9. status of the component (equipment) at the time of the occurrence (Table B.2),
10. abnormal condition associated with the reportable event (e.g., corrosion, vibration, leak) (Table B.5),
11. cause of the reportable event (Table B.2),
12. significance of the reportable event, and
13. comments and/or details on the event.

B.2 Data Sources

The NOAC files of LERs (including the *Sequence Coding and Search System*) were the primary source of information for the review of reportable events. When additional information on the event was needed, the original LER (or equivalent) was consulted by examining (1) those full-sized copies on file at NOAC (for the years 1976—1984); (2) the microfiche file of docket material at NOAC; or (3) the appropriate operating report (semiannual, annual, or monthly).

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Printouts obtained from the computer files also covered other types of "docket material" besides reportable events where the licensee may have been in correspondence with NRC [or the Atomic Energy Commission (AEC)] concerning a particular event. Licensees are often requested to submit additional information or perform further analysis. Before the LERs came into existence in the mid-1970s, it was not unusual for licensees to submit on their own or at the request of NRC or AEC more than one letter transmitting information on a particular event. Thus, these printouts provided additional sources of information on reportable events.

Several special publications were reviewed to provide details on events of significance. These publications provided additional details, evaluations on assessments of the events.

1. *Reports to Congress on Abnormal Occurrences*, NUREG-0090 series;[22]
2. "Power Reactor Event Series" (formerly Current Event Series) published bimonthly by NRC;
3. "Operating Experiences," a section of each issue of the *Nuclear Safety* journal; and
4. the publications of NRC's Office of Inspection and Enforcement (IE), such as operating experience bulletins, IE bulletins, IE circulars, and IE information notices.

B.3 Significance Screening

Two sets of criteria were used in determining the significance of reportable events. The first set of criteria (Table B.6) addresses those events whose results include challenges to the safety protection features of the plant; these events are termed "safety significant". The second set of criteria (Table B.7) addresses those events that have the potential to challenge the safety protection features of the plant. These events, which might require additional information or evaluation to determine their full implication, were termed "conditionally significant".

The reportable events were all reviewed, applying the two sets of criteria for significance rather liberally. A number of significant events and conditionally significant events were noted. The events initially identified as significant or conditionally significant were analyzed and evaluated further based on (1) engineering judgment; (2) the systems, equipment, or components involved; or (3) whether the safety of the plant was compromised. The conditionally significant events were subsequently "upgraded" to significant or "downgraded" to nonsignificant as necessary. The final evaluation for significance considered whether a DBE was initiated or a safety function was compromised such that the system as designed could not mitigate the progression of events. Thus, the number of events finally categorized as significant was reduced considerably by these steps in the review process.

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The reportable events not identified as significant or conditionally significant were categorized as not significant (with an 'N' in the significance column of the coding sheets and in the tables). These events and the events rejected during the additional review step were further reviewed by compiling a tabular summary of the systems to detect trends and recurring problems (Table B.3 provides a listing of the systems).

Table 8.1 Reportable events for Millstone 1

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RS-70-4	85005	11/08/1970	11/17/1970	B	EE	DD HH	N	C	BK	B	N	GAS TURBINE GENERATOR FAILED DURING TEST DUE TO LTA PRESSURE IN LUBE OIL PUMP
AO-70-5	60225	12/04/1970	12/14/1970	B	CE	H OO	N	C	BJ	B	N	ISOLATION CONDENSER ISOLATED DURING TESTS DUE TO DESIGN ERROR
RS-70-6	58011	11/19/1970	11/25/1970	B	CD	OO		C	DJ	C H	N	STEAM ISOLATION VALVE FAILURE-IMPROPER MAINTENANCE PROCEDURE AND OPERATOR ERROR COMBINED (REACTOR SHUTDOWN)
RS-70-06	59927	12/09/1970	12/19/1970	B	CC	E		B	AN	B	C4	EXCESSIVE PIPE MOVEMENT DURING TRANSIENT DUE TO DESIGN ERROR
RS-70-06	59927	12/05/1970	12/19/1970	B	HE	OO		B	AC	D	N	STEAM BYPASS VALVE CAUSED MALFUNCTION OF PRESSURE CONTROL
RS-70-06	59927	12/09/1970	12/19/1970	B	CD	OO		B	AL	E	C6	MSIV CLOSED DUE TO MISSING SPRING IN SOLENOID VALVE
AO-70-7	59595	12/23/1970	01/02/1971	B	RB	J	K	C	AN	B	N	APPROVED WIRING CHANGE NOT TESTED RESULTING IN LOSS OF FULL ROD CONTROL
AO-70-8	59595	12/23/1970	01/02/1971	B	HC	H S		C	AD	E	N	WELDING ERROR CAUSED DECREASE IN CONDENSER VACUUM (REACTOR SHUTDOWN)

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-70-9	59594	12/29/1970	01/06/1971	B	HB	OO		B	AI	D	N	MAIN STEAMLINE BYPASS VALVE FAILURE CAUSED BY BROKEN LINKAGE ON VALVE OPERATOR (REACTOR SHUTDOWN)
AO-70-10	59593	12/31/1970	01/08/1971	B	EE	T DD		C	HE	E	N	SLOW TURBINE START DUE TO REINSTALLATION ERROR IN LUBE OIL PUMP DISC. LINK

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-71-1	62296 63204	01/19/1971	02/01/1971	B	SF-D SF-B	OO	T	C	BI	E	S7	FOUR SIMULTANEOUS VALVE FAILURES RENDER ECCS INOPERABLE (REACTOR SHUTDOWN) TORQUE SWITCHES SET TOO LOW
AO-71-2	61450	01/19/1971	01/25/1971	B	SF-B	OO		C	AK	D	N	GALLED THREADS ON VALVE CAUSE TURBINE CONTROL VALVE TO CLOSE
RO-71-17	62298	02/12/1971	03/09/1971	B	SF IA	OO	I	A	OJ	H	N	ERROR DURING MAINTENANCE ON LEVEL INDICATOR - REACTOR SCRAM ON LOW LEVEL
AO-71-5	62279	02/21/1971	03/03/1971	B	EE	S T MM	T P	B	BD	D	N	GAS TURBINE GENERATOR FAILS TO START
AO-71-6	62300	03/25/1971	04/02/1971	B	CC	OO MM		C	BI	B	N	LOSS OF PRESSURE TO VALVE DURING TEST REACTOR SHUTDOWN
AO-71-7	63140	03/31/1971	04/08/1971	B	SF-B	X OO		C	BD	D	N	MOTOR FAILED ON LPCI VALVE DUE TO SHORT IN WINDINGS
AO-71-8	63139	04/22/1971	04/27/1971	B	EE	MM OO	T	A	OK	A G	N	GAS TURBINE GENERATOR INOPERABLE DUE TO A SWITCH BEING LEFT IN THE WRONG POSITION
AO-71-9 AO-71-10	63125	05/01/1971 05/02/1971	05/12/1971	B	CC HA EB	D U X OO		B	AU AT	D	C8	THREE SIMULTANEOUS FAILURES IN MOTOR CONTROL CENTER DUE TO MOISTURE

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-71-11	64435	05/25/1971	06/04/1971	B	CH	OO	K	B	HD	D	N	FEEDWATER CONTROL VALVE PROBLEMS
AO-71-12	64436	05/27/1971	06/04/1971	B	CJ EE	OO MM	T	B	EE ED	E	CB	FAILURE OF MECHANICAL AND ELECTRICAL VALVE REGULATOR & SHORT CIRCUIT IN SPEED SWITCH ON GAS TURBINE
	64810	06/24/1971	07/12/1971	B	EA		P	B	EG OP	F	N	OFFSITE RELAY TRIPPED REACTOR INADVERTENTLY DURING THUNDERSTORMS (REACTOR SHUTDOWN)
AO-71-13	65552	06/13/1971	08/19/1971	B	SA IA	OO	T	C	AL	E G	N	DRYWELL HIGH PRESSURE SWITCH HAD LOOSE HOLD DOWN SCREWS
AO-71-14	66469	08/30/1971	09/09/1971	B	CD	OO		B	AS	D	N	PLUNGER IN AIR SLIDE VALVE RESISTED MOVEMENT
	67211	09/22/1971	09/22/1971	B	WA SP	DD		C	GA	D	N	INSUFFICIENT HEAD SERVICE WATER PUMPS
AO-71-15	67459 67460	09/17/1971	09/20/1971	B	SF-B	Z		C	AH	B	N	TWO MOTORS BURNED OUT FOR SAME TEST
AO-71-16	67459	09/18/1971	09/28/1971	B	SF-B	CC		C	AC	D	N	LPCI OUTBOARD CONTAINMENT SPRAY VALVE FAILS DUE TO PINS IN WRONG POSITION

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-71-17	68264	09/21/1971	09/30/1971	B	SP WA	DO		C	OA	B	N	SERVICE WATER PUMPS PROVIDE LTA HEAD
AO-71-17	67461	09/27/1971	09/30/1971	B	SP WA	DO		C	OA	D	N	EMERGENCY SERVICE WATER PUMPS PROVIDE LTA HEAD
AO-71-18	67993	09/23/1971	10/04/1971	B	HB	HH OO		B	AB	B	N	TURBINE BYPASS VALVE FAILS-BRITTLE FRACTURE OF STUDS ON LINKAGE, REACTOR SCRAMMED
AO-71-19	67992	09/29/1971	10/08/1971	B	HB	HH OO	N	B		G	N	FAILURE OF STEAM TURBINE BYPASS VALVE, REACTOR SHUTDOWN
AO-71-20	66996	10/10/1971	10/22/1971	B	CC HB	HH OO	N	B	AP BL	B	87	FAILURE OF STEAM TURBINE BYPASS VALVE REACTOR BLOWDOWN
AO-71-21	68303	10/13/1971	10/20/1971	D	IB	DO	N	B	AA BL	E	N	TWO STACK GAS SAMPLE PUMPS FAIL OFF, THIRD TAGGED OUT
AO-71-22	68304	10/31/1971	10/20/1971	D	SF	OO		C	AP	B	N	RIGID AIR-LINES SHOULD HAVE BEEN FLEXIBLE
AO-71-23	68305	10/16/1971	10/20/1971	D	CF	OO		C	AP	G	N	VALVE ACTUATOR FAILED DUE TO LOOSE PARTS FROM VIBRATION
AO-71-24	68788	11/02/1971	11/11/1971	B	EE	HH	T	C	AL	E G	N	GAS TURBINE GENERATOR FAILS TO START DUE TO LOOSE CONNECTION

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
	68307		11/16/1971	B	HB	DO		C	AT	E	N	PUMP IN STANDBY LIQUID CONTROL SYSTEM LEAKED
AO-71-25	68308	11/30/1971	12/09/1971	B	EE	HH T	U	C	HB OJ	H	CS	COLD LUBE OIL CAUSED GAS TURBINE TRIP OFF. OPERATOR DID NOT TURN ON OIL HEATERS
AO-71-26	69199	12/18/1971	12/28/1971	B	CE	H		C	AH	D	N	STRIPPED THREADS ON YOKE SLEEVE CAUSED ISOL. COND. VALVE TO FAIL CLOSED
AO-71-27	69310		12/27/1971	B	IB		H P	B	AL	G	N	ELECTRIC PRESSURE REGULATOR FAILS (REACTOR SHUTDOWN)

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-72-1		02/03/1972	02/15/1972	B	CC IB		M	C	OA	D	N	MAIN STEAM LINE DIFFERENTIAL PRESSURE SENSORS DO NOT MEET MANUFACTURERS SPECS
AO-72-2	39368	02/04/1972	02/15/1972	B	IB	QQ P	M	B	AQ	G	N	FILTER CLOGGED IN ELECTRIC PRESSURE REGULATOR PILOT VALVE (REACTOR SHUTDOWN)
AO-72-3	39314	02/04/1972	02/15/1972	B	EE	NN		B	EF	E	N	GAS TURBINE VIBRATION MONITOR FAILS
AO-72-4	39195	02/08/1972	02/29/1972	B	CC	QQ	M	C	EI	G	N	SET POINT DRIFT IN PRESSURE RELIEF VALVE CONTROLLER
AO-72-5	39317	02/11/1972	02/15/1972	B	SF-B	QQ	M	B	BG	D	N	FAILURE OF LPCI LOW PRESSURE SWITCH
AO-72-6	39177	02/18/1972	02/28/1972	D	CC	M	M	C	EH	D	N	SET POINT DRIFT CAUSES PRESSURE SENSORS IN CONDENSER TO TRIP TOO HIGH
AO-72-7	39177	02/19/1972	02/28/1972	D	CC		M	C	EM	D	N	SET POINT DRIFT IN MAIN STEAM LINE PRESSURE SENSORS
AO-72-8	39218	02/23/1972	03/02/1972	B	CC		M	C	AI	B	N	DELTA P SENSOR FAILED, REACTOR SHUTDOWN
AO-72-9	55348	03/03/1972	03/13/1972	B	SF-D	QQ	T	C		D	N	CLEANUP AUXILIARY PUMP BYPASS VALVE INOPERABLE

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-72-10	55347	03/06/1972	03/13/1972	B	CB	QQ DD	T	B	EI	D	N	LOSS OF MONITORING CAPABILITY OF CONTAINMENT ISOLATION VALVES
AO-72-11	55353	03/09/1972	03/20/1972	B	EE	HH	T	B	EG ED	G	N	GAS TURBINE GENERATOR FAILS TO START-FAULTY SPEED SWITCH
AO-72-12	70045	03/11/1972	04/20/1972	B	IA		T	B	EH	D	N	SET POINT DRIFT
AO-72-13	70045	04/12/1972	04/20/1972	B	IA		T	B	EH	D	N	OF LEVEL SENSORS
AO-72-14	70045	04/18/1972	04/20/1972	B	CC		M T	C	EH	D	N	SET POINT DRIFT OF PRESSURE SENSORS IN MAIN STEAM LINE
AO-72-15	71716	06/08/1972	06/08/1972	B	CB	QQ M OO		C		G	N	IMPROPER ASSEMBLY OF VALVE
AO-72-16	72424	06/24/1972	07/05/1972	B	IA		T	C	EH	D	N	SET POINT DRIFT OF HIGH FLOW SWITCH
AO-72-17	72561	07/13/1972	07/14/1972	B	IA		M	C	EI	D	CB	THREE PRESSURE SENSORS TRIP ABOVE TOLERANCE LIMIT
	72562	06/12/1972	07/13/1972	B	SE	KK		B	AE	D	N	PIPE HANGERS SHIFTED
AO-72-18	72774	07/19/1972	07/20/1972	B	JF		P	C	EI	G	CB	FOUR OF FIVE TIME DELAY RELAYS DO NOT MEET SPECS
	73637		08/09/1972	B	EE	M	M T	C	EH	D	N	SET POINT DRIFT CAUSES DG TO FAIL TO START
AO-72-19	73638	08/10/1972	08/11/1972	B	RA		I	C	EH	D	N	SET POINT DRIFT OF REACTOR VESSEL LOW LEVEL SWITCH

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-72-20	75492	08/15/1972	08/23/1972	B	CE	H	T	C	EH	D	N	ISOLATION CONDENSER FLOW SWITCHES SET POINT DRIFT
AO-72-21	75398	08/31/1972	08/31/1972	B	CB	DD FF		B	AW	D	N	EXCESSIVE COOLANT RATE LEAK DUE TO BAD PUMP SEALS
AO-72-22	75078 75399 75755 77519	09/01/1972	09/11/1972	B	HC	H		B	AR AU OF	B	C4	MAIN CONDENSER TUBES LEAK SALT WATER INTO COOLANT SEALS
AO-72-23	75400	09/11/1972	09/13/1972	C	IA		T I	C	EI	G	N	LOW-LOW WATER LEVEL DETECTOR OUT OF CALIBRATION
AO-72-24	75345	09/25/1972	09/06/1972	B	SC	OO		C	AD AV	E	N	CRACK IN HEADER OF ATMOSPHERIC CONTROL
AO-72-25	75785	10/12/1972	10/25/1972	C	CE	H	T R	C	EH	D	N	ISOLATION CONDENSER PRESSURE SWITCH SET POINT DRIFT ON 3 OUT OF 4 SENSORS
AO-72-26	75910		10/21/1972	C	CH	E		C	AV	D	N	TWO FEEDWATER SPARGER LEAKS
AO-72-27	75902		10/20/1972	C	CA	OO		C	OA	G	N	PENETRATION LEAKS AND ISOLATION VALVE LEAKS DURING TESTING
	76011	08/25/1972	09/23/1972	B	EA	LL		B		D	C5	PLANE CRASHES INTO POWER TRANSFORMER

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
	76871		10/13/1972	C	CE	N	T	C	SH	D	N	SET POINT DRIFT OF 3 ISOLATION CONDENSER SWITCHES

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
	77956		01/26/1973	B	RB	I A		B	AT AR	D G	S7 S2	ACCUMULATORS FOR CONTROL ROD DRIVE FOUND TO BE BAD, ALL REPLACED
AO-73-1	80136	03/07/1973	03/08/1973	B	RB	I		C	BI	D	N	EXCESSIVE SCRAM TIME
AO-73-2	79560	03/19/1973	03/21/1973	B	RB EE	S T R RR	P	B	BI BD	G	N	SCRAM ON BLOWN CONTROL ROD DRIVE FUSE; GAS-TURBINE FAILS TO START
AO-73-3	80110	03/21/1973	03/27/1973	B	CH	DO D		B	AB	G	N	INBOARD BEARING FAILURE
AO-73-4	80274	04/05/1973	04/12/1973	B	CE	R QQ	T	B	BC BA CK	G	CB	ISOLATION CONDENSER ISOLATES ON HIGH FLOW DUE TO INCORRECT MAINTENANCE
AO-73-5	80275	04/05/1973	04/13/1973	B	EE	T RR		C	OJ OA	B	N	GAS TURBINE GENERATOR FAILS TO START AFTER ISOLATION CONDENSER FAILURE-OPERATOR MADE WRONG ADJUSTMENT DURING STARTUP
AO-73-6	80720	04/10/1973	05/10/1973	D	CF	QQ		B	AD AI AN	B	N	VALVE OPERATOR BROKE ON SHUTDOWN COOLING SYSTEM ISOLATION VALVE-IMPROPER SIZED MOTOR
	80710		05/21/1973	D	CH	X		C	AV	D	N	REPORT ON SPARGERS CRACK IN FEEDWATER SYSTEM
	84795	07/10/1973	07/10/1973	C	EE	QG		C	AT	G	N	SHOCK SUPPRESSORS LEAKED HYDRAULIC FLUID, DETERIORATION OF SEALS

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
	82972		07/13/1973	C	CB	OO		B	BA	D	N	RECIRCULATION VENT VALVE LINE LEAKS
AO-73-8	82957	08/02/1973	08/02/1973	C	SF-B		N T	C	EN	D	N	SET POINT DRIFT ON DP SENSORS OF LPCI
	82966		08/08/1973	C	RB	J		C	CA	B	N	CONTROL ROD UNCOUPLED
	82960		08/06/1973	C	CH	I	N	C	AV	D	N	LEAK IN PRESSURE SENSING LINE
AO-73-9	83225	08/13/1973	08/20/1973	C	IA		I	B	AN	E	N	LEVEL SENSORS READ WRONG DUE TO MISMATCH IN VENTILATION AROUND SENSOR
	84017		08/30/1973	C	SF-D	BD QQ		C	BA BC	B	N	FAILURE OF CORE SPRAY VALVE TO OPEN
AO-73-10	84491	09/21/1973	10/01/1973	B	IA	BO	I	B	AT	D	N	MISMATCH IN LEVEL INDICATORS DUE TO VALVE LEAK
AO-73-11	84497	09/22/1973	10/01/1973	B	CH	D		A	BL	G	N	CONDENSATE BOOSTER PUMP BEARING OVER HEATS-REWORK BEARINGS
	84551		11/06/1973	B	SH-B		T I	C		D	N	LEVEL SWITCH FAILED TO TRIP
AO-73-12	88079	12/30/1973	01/07/1974	B	CE	Q		B	AN	D	N	STEAM LEAK IN ISOLATION CONDENSER FLANGE (REACTOR SHUTDOWN)

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
	93695	01/06/1974	02/01/1974	B	CA	OO		B	AD	D	N	PRESSURE RELIEF VALVE LIFTS DUE TO WORN PRELOAD ASSEMBLY
	89250		03/08/1974	B	SS	GG PF		B	AT	B	N	SNUBBERS LEAK
AO-74-1	89398	03/06/1974	03/15/1974	B	CD	GG OO PF		B	AH	B	N	DRYWELL LEAK DUE TO SEAL PACKING FAILURE (REACTOR SHUTDOWN)
	89663		04/01/1974	B	CD	DD QQ OO	F	B	BD CK	C	N	PUMP SUCTION VALVE ON RECIRC. PUMP FAILS TO CLOSE
AO-74-2	92184	05/17/1974	05/28/1974	B	CH	DD D		B	AB	B	N	INBOARD BEARING HPCI CONDENSATE PUMP - SECOND FAILURE
AO-74-5	95148	08/28/1974	09/05/1974	B	SN-D	PF		C	AH	D	N	TEAR IN SEAL AT REACTOR BUILDING TURBINE BUILDING INTERFACE
AO-74-6	95426	09/10/1974	09/25/1974	C	CB	S		C	AO	B	N	WELD CRACKS IN RECIRCULATION LOOP DISCHARGE BYPASS LINE
AO-74-8	97877	10/31/1974	11/06/1974	C	HA SP-D	OO		C	BA	B	N	EMERGENCY SERVICE WATER VALVE FAILS DUE TO MANUAL OVERTORQUEING
AO-74-9	97876	11/04/1974	11/12/1974	B	CD	OQ P		C	HC	G	N	FOREIGN MATERIAL IN AIR SLIDE VALVE DISABLES VALVE OPERATOR (REACTOR SHUTDOWN)
AO-74-10	97586	11/15/1974	11/18/1974	B	CD	OO P		C	HC	G	N	AIR SLIDE VALVE CLOSE SECOND TIME IN ONE MONTH (REACTOR SHUTDOWN)

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-11	98161	12/13/1974	12/19/1974	B	CG	QQ		A	AB BC	D	N	MISALIGNMENT OF GEAR TRAIN ON VALVE MOTOR OPERATOR
AO-74-12	98582	12/20/1974	12/30/1974	B	CE	H	I	C	EN	D	N	SET POINT DRIFT IN LEVEL SENSOR IN ISOLATION CONDENSER-SET POINT LOCK INSTALLED
AO-74-13	98581	12/20/1974	12/30/1974	B	HC	H	M	C	EN	D	N	SET POINT DRIFT ON CONDENSER VACUUM SWITCHES
AO-74-14	98705	12/23/1974	01/02/1975	B	SF-D	HH	I	B	HC BT	G	N	LEVEL SENSOR TUBING BLOCKED-BLOWOUT TUBE INSTALLED
AO-74-15	98706	12/28/1974	01/02/1975	B	SS	OG		C	AT	B	N	2 SNUBBERS HAVE NO FLUID-IMPROPER INSTALLATION

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
	99684		01/24/1975	B	WC	H		B	OF	D	C8	HYDROGEN EXPLOSION IN ACID DAY TANK DUE TO MOISTURE
AO-75-2	93569	01/25/1975	01/30/1975	B	CC	S	E	B	AD	D	N	FLOW INDICATOR READING DECREASES DUE TO WELD CRACK IN SENSING LINE
AO-75-4	93515	01/29/1975	01/31/1975	B	EE	MN T	P	B	EF	D	N	SPURIOUS OPERATION OF RELAY CAUSES TURBINE STARTUP SEQUENCE TO BEGIN
AO-75-5	101408	03/27/1975	04/03/1975	N	WP MA	V		B	AW OD	E	N	WIRING ERROR CAUSES FLOW OF CONTAMINATE INTO BOILER SYSTEM
AO-75-6	101701	03/30/1975	04/08/1975	B	MA			B	OD OK	A	C3	INADVERTENT DISCHARGE OF RADIOACTIVE LIQUID DUE TO PROCEDURE ERROR
AO-75-7	102297	04/18/1975	04/24/1975	B	EE	T C	P	B	EB	D	N	OSCILLATOR BOARD TRIPS INVERTER OPERATION
AO-75-8	103148	05/20/1975	05/29/1975	B	EE	MN T QQ	T U	C	EI BL	G	N	INCORRECT VALVE POSITION PLUS TEMPERATURE SENSOR ERROR CAUSES GAS TURBINE TRIP
AO-75-9	104066	05/20/1975	07/11/1975	B	CC	OO		B	BP BB	D	N	SAFETY RELIEF VALVE FAILS TO RESET-NO CAUSE FOUND (REACTOR SHUTDOWN)

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-75-10	103074	05/21/1975	05/28/1975	B	EE	GG FF		A	BT	B E	N	NO FLUID IN TWO SNUBBERS DUE TO IMPROPER ASSEMBLY
AO-75-11	103879	06/26/1975	07/02/1975	B	CC		T M	C	AR AU	G	N	MOISTURE FROM LEAK CAUSES SWITCH FAILURE
AO-75-14	105035	07/14/1975	07/22/1975	B	CE	H	E T	C	EN	D	N	SET POINT DRIFT IN FLOW SENSORS ON ISOLATION CONDENSER
AO-75-15	104868	07/22/1975	08/01/1975	B	CC	MM	M	B	HD	B	N	VARIATION IN DIFF. PRESSURE DATA DUE TO SENSING TUBE FAILURE
AO-75-16	106457	08/16/1975	08/22/1975	B	IA		M T	C	EN	D	N	SET POINT DRIFT ON VESSEL HIGH PRESSURE SWITCH
AO-75-17	105547	08/18/1975	08/26/1975	B	CC	QQ		C	AQ	G	N	SAFETY/RELIEF VALVE BELLOWS INTEGRITY COULD NOT BE VERIFIED DUE TO GRIT IN AIR LINES
AO-75-18	106343	09/08/1975	09/15/1975	B	IB	BB	M T	C	EN	D	N	SET POINT DRIFT OF HIGH PRESSURE SWITCHES
AO-75-19	107502	10/12/1975	10/21/1975	C	IA		U T	C	EN	D	N	SET POINT DRIFT ON STEAM TUNNEL TEMPERATURE SENSORS
AO-75-20	107501	10/13/1975	10/22/1975	C	IB		M T	C	EN	D	N	SET POINT DRIFT OF VENTILATION RADIATION MONITOR

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-75-21	108248	11/13/1975	11/25/1975	B	CB	S		B	AO AI AN	B	N	INSTRUMENT PIPE WELD CRACK DUE TO FATIGUE
AO-75-22	108520	11/24/1975	12/03/1975	B	HC		M T	C	EN	D	N	SET POINT DRIFT IN CONDENSER LOW VACUUM SWITCH
AO-75-23	108889	12/09/1975	12/18/1975	B	IB	BB	M T	C	EN	D	N	SET POINT DRIFT OF DRYWELL HIGH PRESSURE SWITCHES
AO-75-24	108888	12/19/1975	12/23/1975	B	CD		P T	C	BC	G	N	VALVE POSITION SWITCH OUT OF POSITION CAUSES MSIV RELAY TO FAIL
AO-75-25	109191	12/17/1975	12/23/1975	B	IB		F	C	EN	D	N	SET POINT DRIFT IN RELAY
AO-75-26	109456	12/30/1975	01/07/1976	B	WA	P		C	AQ	G A	N	GRIT IN STRAINER CAUSES EMERGENCY SERVICE WATER PUMP TRIP
AO-75-27	109459	12/23/1975	01/07/1976	B	SF-B		M T	C	EN	D	N	SET POINT DRIFT IN LPCI PRESSURE SWITCH
RO-75-28	110932		12/20/1976	B	CG	JJ		B	AR	D	N	HOLE IN CLEANUP FILTER SLUDGE TANK

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-2	111648	01/26/1976	02/25/1976	B	SA	F		C	AA	D	N	VACUUM BREAKER FAILS DUE TO TEFLON BUSHING OUT OF ROUND
RO-76-3	111658	02/10/1976	03/09/1976	B	HC	H	H T	C	EH	D	N	SET POINT DRIFT IN CONDENSER LOW VACUUM SWITCH
RO-76-4	111647 120080	02/12/1976	03/05/1976 09/28/1976	B	CD	H		B	AB	A B	S7	ISOLATION CONDENSER TUBE FAILURE DUE TO CORROSION CRACKING
RO-76-5	112163	02/12/1976	03/12/1976	D	CH	DD	H	B	AI	D	N	FEEDWATER REGULATION VALVES LOCK DUE TO DIAPHRAGM FAILURE IN REGULATOR
RO-76-7	112308	02/19/1976	03/15/1976	B	CC	HH	H T	C	EH	D	N	INSTRUMENT DRIFT CAUSES TURBINE RELAYS TO TRIP
RO-76-8	111191	02/29/1976	03/15/1976	B	EE	HH T		C	BC	G	N	GAS TURBINE GOVERNOR OUT OF ADJUSTMENT
RO-76-10	112309	03/08/1976	03/22/1976	B	EE	HH T		C	BC	G	S7 S1	GAS TURBINE GENERATOR GOVERNOR OUT OF ADJUSTMENT (REACTOR SHUTDOWN)
RO-76-11	112162	03/09/1976	03/23/1976	B	IE	GG		C	BT AU	G	N	SHOCK SUPPRESSOR LOW ON FLUID
RO-76-12	112310	03/15/1976	03/29/1976	B	EE	HH T		C	BC	D	N	GAS TURBINE GENERATOR INOPERABLE DUE TO GOVERNOR FAILURE WHILE ISOLATION CONDENSER UNAVAILABLE

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-16	113541	04/22/1976	05/04/1976	B	CD	OO		C	AG	D	N	PRIMARY CONTAINMENT ISOLATION VALVES FAIL TO CLOSE DUE TO INTERNAL BINDING
RO-76-17	113588	04/23/1976	04/30/1976	B	RB	R		B	OG	B	C3	EXCESS STACK GAS RELEASE DUE TO FUEL CLAD PERFORATIONS
RO-76-23	114643	05/20/1976	06/11/1976	B	CD	H		B	BU	E	N	INCREASE IN CHLORIDE ION CONCENTRATION IN CONDENSER RETURN LEG
RO-76-27	115725	06/23/1976	07/09/1976	B	IA		M T	B	EH	D	N	SET POINT DRIFT IN PRESSURE SWITCH
RO-76-28	116269	07/14/1976	07/30/1976	D	RC	QQ		C	CA	E	N	ISOLATION CONDENSER INBOARD ISOLATION VALVE INOPERABLE DUE TO PREVIOUS FIX FOR LEAK
RO-76-29.	116788	08/10/1976	08/24/1976	B	EE	HH T		C	EA BF	B	S6 S7	GAS TURBINE GENERATOR TRIPS OUT ON INCORRECT AC FEED
RO-76-30	117678	08/31/1976	09/08/1976	B	EE	HH T		C	BF	D	N	GAS TURBINE GENERATOR TRIPS ON OVERSPEED - SPEED SWITCH FAULTY
RO-76-31	117679	08/13/1976	09/09/1976	D	IA		L	C	EH	D	N	SET POINT DRIFT IN INTERMEDIATE RANGE MONITORS
RO-76-32	118795	09/25/1976	10/08/1976	B	SF-B	PP		B	AW	G	N	PACKING LEAK IN LPCI TESTABLE CHECK VALVE

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-33	120533	10/28/1976	11/23/1976	C	RB	R		C	AD	D	N	NEUTRON SOURCE ROD BROKEN
RO-76-34	120436	11/12/1976	11/26/1976	C	RB	I		C	GJ GK	A E	SS	INADVERTENT CRITICALITY DUE TO OPERATOR ERROR DURING SHUTDOWN MARGIN TEST
RO-76-35	120272	11/09/1976	12/03/1976	C	CC		U T	C	BN	D	N	SET POINT DRIFT OF STEAM TUNNEL TEMPERATURE SWITCH
RO-76-36	120228	11/22/1976	11/27/1976	C	SF-D	S		C	AO AV	B	N	WELD JOINT LEAK IN HEAD SPRAY SYSTEM DUE TO STRESS CORROSION
RO-76-37	120670	12/07/1976	12/30/1976	B	IA		H T	C	BN	D	N	SET POINT DRIFT IN DRYWELL PRESSURE SWITCHES
RO-76-38	120669	12/10/1976	12/30/1976	B	SH-B		H T	C	BN	D	N	SET POINT DRIFT OF CONTAINMENT SPRAY PRESSURE SWITCHES
RO-76-40	121055	12/14/1976	01/12/1977	B	CC		H T	C	BN	D	N	SET POINT DRIFT IN MAIN STEAM LINE FLOW SWITCH
RO-76-42	121034	12/17/1976	01/14/1977	B	CB	VO	T	C	BB EI	G	N	ISOLATION CONDENSER STEAM SUPPLY VALVE FAILS TO CLOSE DUE TO INCORRECT TORQUE SWITCH SETTING (REACTOR SHUTDOWN)
RO-76-43	121035	12/18/1976	01/14/1977	B	CB	VO	T	C	BO EI	G	N	ISOLATION CONDENSER CONDENSATE RETURN VALVE TORQUE SWITCH MISCALIBRATED

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-66	121836	12/16/1976	01/14/1977	B	CG	QQ X		C	AH BA OK	G	M	PROCEDURE ERROR CAUSES OVERLOAD OF MOTOR ON VALVE

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-77-2	122286	01/08/1977	02/07/1977	B	BB	AA S	N	B	EA	B	C4	BOTH STACK GAS MONITORS INOPERABLE DUE TO BLOWN FUSE IN POWER SUPPLY
RO-77-3	122174	01/12/1977	02/10/1977	B	IA		N T	C	EN	D	N	SET POINT DRIFT IN DRYWELL PRESSURE SWITCH
RO-77-4	122136	01/25/1977	02/23/1977	B	SA	QQ MM		B	AQ BB	G	N	DRYWELL VENT BYPASS VALVE FAILS TO CLOSE DUE TO GRIT IN AIR OPERATOR LINE
RO-77-5	122137	01/26/1977	02/24/1977	B	CB	N		B	BU	G	N	HIGH COOLANT CONDUCTIVITY DUE TO IMPROPER RINSING OF RESIN IN DEMINERALIZER (REACTOR SHUTDOWN)
RO-77-6	122138	01/28/1977	02/28/1977	B	CB	N		A	OF	I	N	IMPENDING STORM CONDITIONS HALTS MAINTENANCE OF ISOLATION CONDENSER
RO-77-7	122429	02/01/1977	03/01/1977	B	EE	Y T N		C	OA AT AV	D	N	DIESEL GENERATOR INOPERABLE DUE TO FUEL OIL LEAK - CRACKED NIPPLE
RO-77-8	122139	02/01/1977	02/28/1977	B	CB	N		A	BU	B	N	HIGH CHLORIDE ION CONCENTRATION IN ISOLATION CONDENSER
RO-77-9	123022	02/11/1977	03/11/1977	B	IA		I T	C	EN	D	N	SET POINT DRIFT IN REACTOR WATER LEVEL SWITCH

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-77-10	123023	02/14/1977	03/11/1977	B	IA	BB	M T	C	EN	D	N	SET POINT DRIFT IN DRYWELL PRESSURE SWITCH
RO-77-11	129462	02/14/1977	03/14/1977	B	CC		M T	C	EN	D	N	SET POINT DRIFT IN MAIN STEAM LINE PRESSURE SWITCH
RO-77-12	123024	02/15/1977	03/14/1977	B	HC	H	M T	C	EN	D	N	SET POINT DRIFT IN CONDENSER VACUUM SWITCH
RO-77-13	124872	03/18/1977	03/30/1977	B	SF-B			C	BV	A	N	LOW CONCENTRATION IN STANDBY LIQUID CONTROL SYSTEM DUE TO LOW TEMP IN STORAGE TANK
RO-77-14	125214	05/03/1977	05/17/1977	B	IA		M T	C	EN	D	N	SET POINT DRIFT IN REACTOR LOW PRESSURE START PERMISSIVE SWITCH
RO-77-15	125177	05/14/1977	06/07/1977	B	SH-D	S		B	EN OA	D	N	STANDBY GAS TREATMENT SYSTEM CIRCUIT HAD BLOWN FUSE
RO-77-16	125594	06/14/1977	06/27/1977	B	CB	S		A	AW	D	N	LEAK IN RECIRCULATION LOOP DRAIN - CAUSE UNKNOWN
RO-77-17	130698	06/17/1977	06/17/1977	B	CC	OO		C	AT	D	N	SAFETY/RELIEF VALVE OPENS - NO CAUSE KNOWN
RO-77-18	126008	06/18/1977	07/01/1977	B	CC	OO F		B	AT	D	N	SAFETY/RELIEF VALVE SEAT LEAKAGE DUE TO FILTER FAILURE

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-77-19	126489	06/15/1977	07/15/1977	B	CE	H	M T	C	EN	D	N	SET POINT DRIFT IN ISOLATION CONDENSER ACTUATION PRESSURE SWITCH
RO-77-20	143504	07/14/1977	07/26/1977	B	BB	DD		C	AC	D	N	COOLING FAN DETERIORATION CAUSES LOSS OF STACK SAMPLER
RO-77-21	143468	07/13/1977	08/05/1977	B	CH	OO		B	AC	D	N	DEGRADATION OF VALVE DIAPHRAGM CAUSES LOSS OF FULL FWCI CAPABILITIES
LER-77-22	143507	07/21/1977	08/19/1977	B	CC	OO G	A	B	BD	D	N	SAFETY/RELIEF VALVE BELLOWS ALARM RECEIVED DUE TO WIRING SHORT CIRCUIT
RO-77-23	143469	08/05/1977	08/31/1977	B	IC	F		B	AB	B	N	3 VACUUM BREAKERS FAIL TO CLOSE DUE TO FRICTION
RO-77-24	143470	08/06/1977	08/30/1977	B	IX	OO		B	AC	B	N	REACTOR SCRAM ON LOSS OF INSTRUMENT AIR CAUSED BY GASKET FAILURE (REACTOR SHUTDOWN)
LER 77-25	143509	08/07/1977	08/30/1977	B	CC	OO	K T	C	AC	D	N	PRESSURE SWITCH ON BELLOWS MONITOR FAILS
LER 77-27	143511	09/09/1977	10/07/1977	B	EE	NN		C	BG	D	N	SPURIOUS NOISE HALTS GAS TURBINE STARTUP TESTS

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER 77-28	143512	09/12/1977	10/11/1977	B	CE	H	H T	B	EH	D	N	SET POINT DRIFT IN ISOLATION CONDENSER PRESSURE SWITCHES
RO-77-29	143561	09/27/1977	10/14/1977	B	EE	H HH		B	AT	D	N	DIESEL GENERATOR INOPERABLE DUE TO FUEL OIL LEAK
RO-77-30	143471	10/12/1977	11/02/1977	B	SH-D	FF		C	AV	D	N	STANDBY GAS TREATMENT SYSTEM INOPERABLE DUE TO LEAK IN SEAL
LER 77-32	143555	11/01/1977	11/15/1977	B	BB	DD		B	AA	D	N	STACK SAMPLE PUMP TRIPS DUE TO NORMAL PUMP
LER 77-33	143543	11/10/1977	12/02/1977	B	RX CC	OO	H	B	BP	D	C6	REACTOR COOLDOWN RATE EXCEEDED LIMIT WHEN A SAFETY/RELIEF VALVE LIFTED AT LOW PRESSURE
LER 77-34	143546	10/28/1977	11/23/1977	B	CC	OO	A	B	ED	E	N	BELLOWS LEAKAGE ALARM SOUNDS DUE TO WIRING SHORT CIRCUIT
RO-77-35	143472	10/31/1977	11/29/1977	B	CE	QQ		B	OA	D	N	ISOLATION CONDENSER STEAM SUPPLY VALVE INOPERABLE DUE TO UNKNOWN CAUSE
LER 77-36	143547	11/07/1977	12/02/1977	B	IA		I T	C	AG AQ	G	N	LOW-LOW LEVEL SWITCH FAILS TO TRIP DUE TO GRIT

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER 77-37	144121	11/30/1977	03/03/1978	C	SS	GG		C	OA	E	N	TWO SNUBBERS ARE DECLARED INOPERABLE
RO-77-38	143485	11/10/1977	12/09/1977	B	SF-B	QQ		C	ED	G	C8	MAINTENANCE FOREMAN INADVERTENTLY SHORT CIRCUITS VALVE OPERATOR ON LPCI VALVE
RO-77-39	144187	12/10/1977	12/12/1977	B	EE	H HH		C	OA	D	S1 S7	DIESEL GENERATOR IS DECLARED INOPERABLE, GAS TURBINE UNAVAILABLE
RO-77-40	144186	12/13/1977	12/14/1977	B	SC					G	S9	2 HYDROGEN EXPLOSIONS IN OFF-GAS SYSTEM (REACTOR SHUTDOWN)
RO-77-43	133684	12/19/1977	01/18/1978	D	SB	XX	N	A	BC	H	N	STACK GAS SAMPLER AND STRUCTURE DAMAGED DUE TO HYDROGEN EXPLOSION

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-78-1	134979	01/16/1978	02/14/1978	B	CC		H T	C	SH	D	N	SET POINT DRIFT IN MAIN STEAM LINE LOW PRESSURE SWITCHES
RO-78-2	134961	01/17/1978	02/14/1978	B	SH-D	F		C	AA	D	N	PRESSURE DROP LIMIT EXCEEDED DUE TO NORMAL WEAR OF FILTER
RO-78-3	136464	02/14/1978	02/28/1978	B	HA	UU	F	C	SH	D	N	SET POINT DRIFT IN TURBINE CONTROL TIME DELAY RELAY
RO-78-4	142572	03/10/1978	03/24/1978	C	IB	OO		B	DB	D	N	SAFETY/RELIEF VALVE FAILS TO RESEAT - CAUSE UNKNOWN
RO-78-5	137251	03/19/1978	04/03/1978	C	CB	OO S		A	AO AI AT	B	N	FATIGUE CAUSES WELD LEAK IN RECIRCULATION DISCHARGE VALVE VENT LINE
RO-78-6	137252	03/20/1978	04/03/1978	C	CD	OO		A	AT	D	N	CONTAINMENT ISOLATION VALVE EXCESS LEAKAGE
RO-78-7	137584	03/11/1978	04/10/1978	C	CE	H S		A	BS	C	N	PIPE MOVEMENT IN ISOLATION CONDENSER DUE TO WATER IN STEAM LINES
RO-78-8	137586	04/17/1978	04/28/1978	B	SF-B SF-D	HK		B	AH	B	N	DEGRADATION OF CORE SPRAY AND LPCI PIPING SUPPORT STRUCTURE DUE TO POOR DESIGN

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-78-9	138250	04/03/1978	04/25/1978	B	CC		N T	C	EN	D	N	SET POINT DRIFT IN STEAM TUNNEL TEMPERATURE SWITCHES
RO-78-10	138838	04/24/1978	05/23/1978	B	RB	J OO		C	BI	E	N	SCRAM TIME TOO SLOW FOR CONTROL RODS DUE TO TIGHT PACKING ON VALVE
RO-78-11	139384	05/08/1978	06/06/1978	B	IA		N T	C	EN	D	N	SET POINT DRIFT IN CONTAINMENT PRESSURE SWITCH
RO-78-12	139640	05/19/1978	06/16/1978	D	EE	HH T		C	BI BI	D	N	GAS TURBINE FAILS TO COMPLETE STARTUP SEQUENCE DUE TO INCORRECT GOVERNOR SETTING
RO-78-13	139817	05/29/1978	06/20/1978	D	CE	H		B	BL	G	N	STEAM TRAP BLOWBY CAUSES ISOLATION CONDENSER TO BE REMOVED FROM SYSTEM
RO-78-14	139876	06/13/1978	07/12/1978	B	EE	HH T	T	B	BW	D	N	GAS TURBINE TRIPS OUT DUE TO OVERSPEED SWITCH FAILURE
RO-78-16	140261	07/05/1978	08/04/1978	B	HC	H	N T	B	EN	D	N	SET POINT DRIFT IN CONDENSER LOW VACUUM SWITCH
LER 78-16	140386	07/25/1978	08/09/1978	B	SH-A		A	B	OK	G	CS	PROCEDURAL ERROR ALLOWED CONTAINMENT TO BE PURGED WITHOUT HIGH RADIATION MONITOR

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-78-17	148032	07/10/1978	08/04/1978	B	FB		M	C	EI	G	N	CALIBRATION ERROR IN SPENT FUEL STORAGE AIR MONITORS
RO-78-18	141762	09/05/1978	10/04/1978	B	IA		I	C	AK	G	N	LACK OF LUBRICATION CAUSES LOW-LOW WATER LEVEL SENSORS TO FAIL
RO-78-19	141763	09/12/1978	10/10/1978	B	IA HA	HH	F	C	EH	D	N	SET POINT DRIFT IN TURBINE CONTROL TIME DELAY RELAY
RO-78-20	148110	10/10/1978	10/10/1978	B	HC	M		B	OA	D	N	CHLORINE CAPACITY OF DEMINERALIZER LESS THAN TECHNICAL SPECIFICATION
RO-78-21	141139	09/14/1978	10/12/1978	D	EE	HW	T	C	BF	D	N	FAULTY SPEED SWITCH TRIPS GAS TURBINE
RO-78-22	141169	09/14/1978	10/13/1978	D	SS	QQ BB		B	AQ	G	N	DRYWELL VENT BYPASS VALVE FAILS TO CLOSE DUE TO DIRT IN AIR OPERATOR
RO-78-23	141726	10/11/1978	11/06/1978	B	IA	BB	M T	C	EH AK	D	N	SET POINT DRIFT IN DRYWELL HIGH PRESSURE SWITCH
RO-78-24	141729	10/19/1978	11/16/1978	N	CE	QQ E	T	B	BF	G	N	SPURIOUS OPENING OF ISOLATION CONDENSER ISOLATION VALVE DUE TO SET POINT DRIFT

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-78-26	142286	11/06/1978	11/30/1978	B	IA	BB	H T	C	EH	D	N	SET POINT DRIFT IN DRYWELL HIGH PRESSURE SWITCH
RO-78-27	142285	11/06/1978	12/01/1978	B	IA		I	C	EH	D	N	SET POINT DRIFT IN REACTOR LOW LEVEL SWITCH
RO-78-29	142849	11/22/1978	12/22/1978	B	EE	HH T	G	C	DA AA	G	N	GAS TURBINE INOPERABLE WHEN MAINTENANCE CREW HAD TO REPAIR DAMAGED INDICATOR LIGHT SOCKET
LER 78-30	146505	12/10/1978	01/17/1979	B	SE	BB			OK BU	A	N	EXCESS OXYGEN IN DRYWELL DUE TO PROCEDURAL ERROR

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-1	146724	01/06/1979	01/18/1979	D	CG	E		A	AD AV	D	N	STRESS CORROSION CRACKING OF CLEANUP SYSTEM RETURN LINE WELD (REACTOR SHUTDOWN)
LER-79-2	146643	01/07/1979	02/06/1979	D	SH-D		P	B	BC BD	E	N	STANDBY GAS TREATMENT SYSTEM 'A' FAILS TO START DUE TO MISALIGNMENT OF STARTUP RELAY
LER-79-3	146646	01/08/1979	02/07/1979	D	CC ID		M T	C	EH	D	N	SET POINT DRIFT IN MAIN STEAM LINE PRESSURE SWITCH
LER-79-4	147428	01/25/1979	02/23/1979	B	RB	I		C	AG	D	N	CONTROL ROD STICKS - CAUSE UNKNOWN
LER-79-5	147414	02/26/1979	02/26/1979	B	CC	QQ		B	AB	D	CB	PRESSURE RELIEF VALVE LIFTS PREMATURELY AND FAILS TO SEAT DUE TO STEAM CUTTING OF DISC (REACTOR SHUTDOWN)
LER-79-6	147295	02/01/1979	03/02/1979	B	RB	I		B	DJ	H	CB	2 CONTROL RODS INOPERABLE DUE TO OPERATOR ERROR
LER-79-7	147413	02/14/1979	03/09/1979	B	EE	HH T	T	C	BD	D	E	GAS TURBINE GENERATOR FAILS TO START DUE TO FAULTY SPEED SWITCH
LER-79-8	147415	02/14/1979	03/14/1979	B	CE ID	QQ	E	A	AD	D	N	RCIC VALVE LOSES POSITION INDICATOR DUE TO FAILURE OF VALVE OPERATOR CASING

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-9	148229	02/22/1979	03/22/1979	D	CC	OO	G	C	OA AV	D	N	SAFETY/RELIEF VALVE BELLOWS MONITOR INOPERABLE DUE TO CRACK IN AIR TUBE FITTING
LER-79-10	149268	04/03/1979	04/18/1979	B	RC			B	OJ	H	N	CORE THERMAL POWER EXCEEDS TECHNICAL SPECIFICATIONS DUE TO OPERATOR ERROR
LER-79-11	149267	03/17/1979	04/17/1979	B	CD	OO	P	C	BB BC	D	N	MSIV RELAY FAILS TO DEENERGIZE DUE TO MALADJUSTMENT OF RELAY LIMIT SWITCH (REACTOR SHUTDOWN)
RO-79-11	152303	05/16/1979	05/18/1979	C	SA	E		A	AA	D	N	PENETRATION LEAK RATE EXCEEDED
LER-79-12	149544	04/23/1979	05/21/1979	B	RA		M	C	EH	D	N	SET POINT DRIFT IN REACTOR BUILDING RADIATION MONITOR
LER-79-15	150110	05/20/1979	06/22/1979	C	RB	J	K	C	AM	D	N	CONTROL ROD OUT BLOCK FUNCTION FAILS DUE TO WORN LIMIT SWITCH
LER-79-16	150109	05/30/1979	06/29/1979	C	IA		M T	C	EH	D	N	SET POINT DRIFT IN REACTOR LOW PRESSURE SWITCH
LER-79-17	150108	06/02/1979	06/28/1979	C	IA		U T	C	EH	D	N	SET POINT DRIFT IN STEAM TUNNEL TEMPERATURE SWITCH

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-18	150748	07/13/1979	07/26/1979	B	SF-B			A	OK BU	A	CB	CONCENTRATION IN STANDBY LIQUID CONTROL SYSTEM LTA DUE TO PROCEDURAL ERROR
LER-79-19	150782	06/28/1979	08/03/1979	D	CE	OO		C	AA AU	D	N	CONTAINMENT ISOLATION VALVE LEAKAGE DUE TO NORMAL WEAR
	150990	02/16/1979	03/19/1979	B	IA		G	B	BU OK	A	N	ABNORMAL OXYGEN LEVELS IN CONTAINMENT DUE TO CANCELLATION OF SHUTDOWN
LER-79-20	151245	07/11/1979	08/09/1979	B	IA		I T	C	EE	D	N	SET POINT DRIFT IN REACTOR LOW-LOW LEVEL SWITCH
LER-79-21	151248	07/12/1979	08/10/1979	B	IA		I T	C	AQ	G	N	LOW-LOW WATER LEVEL SWITCH FAILS TO TRIP DUE TO GRIT ON SHAFT ASSEMBLY
LER-79-22	151211	07/23/1979	08/22/1979	B	SC	OO		B	BB	D	N	CONTAINMENT VENT BYPASS VALVE FAILS TO CLOSE - CAUSE UNKNOWN
LER-79-23	151207	08/08/1979	08/24/1979	B	SC	OO		B	BB	D	N	CONTAINMENT VENT BYPASS VALVE FAILS TO CLOSE - CAUSE UNKNOWN
LER-79-24	151425	07/31/1979	08/30/1979	B	RA		N	C	EE	D	N	SET POINT DRIFT IN REFUELING FLOOR RADIATION MONITOR
LER-79-25	151913	09/13/1979	09/25/1979	B	RB			B	OK	B	N	TOTAL PEAKING FACTOR IN ERROR DUE TO DESIGN OVERSIGHT

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-26	151912	09/14/1979	09/27/1979	B	SF			B	OK	B	E7	POTENTIAL EXISTS FOR LOSS OF POWER TO ECCS TO GO UNDETECTED - DESIGN ERROR
LER-79-27	151750	08/27/1979	09/24/1979	B	AB			B	OC	G	N	SYSTEM NOT TESTED ACCORDING TO SCHEDULE
LER-79-28	151911	08/28/1979	09/25/1979	B	CC	QQ		C	BB AB	D	N	PRESSURE SUPPRESSION CHAMBER VENT BYPASS VALVE FAILS TO CLOSE DUE TO RUST BUILDUP
LER-79-29	151930	09/04/1979	10/04/1979	B	CE	QQ N	T	C	BB	D	N	ISOLATION CONDENSER ISOLATION VALVE FAILS TO CLOSE DUE TO FAULTY MICROSWITCH
LER-79-30	152948	10/09/1979	11/08/1979	B	EE	EE N *		B	AL	E	N	SERVICE WATER SYSTEM PIPES TO DIESEL GENERATOR NOT RESTRAINED DUE TO INSTALLATION ERROR
LER-79-31	153647	10/16/1979	11/15/1979	B	SF-C	HX		B	OA AL	E	N	FEEDWATER COOLANT INJECTION SYSTEM DECLARED INOPERABLE DUE TO MISSING SUPPORT STRUCTURE
LER-79-32	153362	11/06/1979	12/03/1979	B	IA		H T	C	BH	D	N	SET POINT DRIFT IN DRYWELL PRESSURE SWITCHES

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-33	15.	11/13/1979	12/04/1979	D	IA CC		S T	C	EH	D	N	SET POINT DRIFT IN MAIN STEAM LINE DELTA P SWITCH
LER-79-34	153789	11/15/1979	12/14/1979	D	SF-B	QO E		C	BA ED	D	N	LPCI VALVE INOPERABLE DUE TO ELECTRICAL FAULT IN MOTOR CONTROLLER
LER-79-35	153986	12/04/1979	12/28/1979	D	IA		S T	C	EH	D	N	SET POINT DRIFT IN MAIN STEAM LOW PRESSURE SWITCH
RO-79-36	153982	12/19/1979	01/18/1980	D	CB	S H		B	DH	B	N	WATER HAMMER IN ISOLATION CONDENSER PIPING

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-80-01	154444	01/03/1980	02/01/1980	B	CB	DD		B	BW	D	N	PUMP SPEED MISMATCH DURING RECIRCULATION PUMP RUNBACK
LER-80-001	155196	01/31/1980	02/14/1980	B						B	N	MAPLHGR WRONG
LER-80-3	154616	01/04/1980	02/04/1980	B	CB	KK		B	AH	B	N	STRUCTURAL DEFICIENCY IN ISOLATION CONDENSER STEAM SUPPLY LINE (REACTOR SHUTDOWN)
LER-80-4	155195	01/21/1980	02/14/1980	B	IA CC		H T	C	EN	D	N	SET POINT DRIFT IN MAIN STEAM LINE HIGH FLOW SWITCH
LER-80-5	156005	02/20/1980	03/17/1980	B	SF-D	KK		C	AC WH	D	N	CORE SPRAY SUPPORTS DAMAGED BY WATER HAMMER
LER-80-6	156157	04/07/1980	04/21/1980	B	IA		H T	C	OK	E	N	PRESSURE SENSOR ISOLATES DUE TO INSTALLATION ERROR
LER-80-8	158283	06/05/1980	07/02/1980	B	SA		H T	C	EN	D	N	SET POINT DRIFT IN TWO REACTOR PRESSURE SWITCHES
LER-80-9	158276	06/05/1980	07/02/1980	B	IA		H T	C	EN	D	N	SET POINT DRIFT IN REACTOR PROTECTION LOW PRESSURE SWITCHES
LER-80-10	159128	06/13/1980	07/11/1980	B	BA	KK		B	AC	E	N	BOLTS ON PENETRATION BASE PLATE FAULTY DUE TO INSTALLATION ERROR

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-80-11	160233	08/03/1980	08/15/1980	B	BB	OO	N	C	BC GA	G	N	OFF GAS RADIATION MONITORING SYSTEM INOPERABLE DUE TO VALVE MISALIGNMENT
LER-80-12	159269	07/25/1980	08/22/1980	B	IC		N	C	BI	G	N	APRM READS LOW DUE TO CALIBRATION ERROR
LER-80-13	160459	09/08/1980	10/03/1980	B	IA		M T	C	EN	D	N	SET POINT DRIFT IN HIGH PRESSURE SWITCH
LER-80-14	160060	10/05/1980	10/16/1980	C	CD	OO		C		D	N	LEAK RATE TEST FAILURE OF TWO MSIV'S
LER-80-15	160923	10/07/1980	10/24/1980	C	IA		I T	C	AQ	G	N	SET POINT DRIFT IN LOW WATER LEVEL SCRAM SWITCH - GRIT
LER-80-16	161870	10/23/1980	11/06/1980	C	CB	DD KK		C	AN	C	N	CRACKS FOUND IN JET PUMP SUPPORT BEAMS
LER-80-18	161470	11/05/1980	11/19/1980	C	CC	E		C	AO	D	N	WELD FAILURE IN TWO MAIN STEAM LINES
LER-80-19	161471	11/06/1980	11/20/1980	C	CC	T		C	AO	D	N	CONDENSER NOZZLE WELD CRACKS DUE TO STRESS CORROSION

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-01	164391	02/09/1981	02/23/1981	C	SF-B	S		C	AV	D	C8	A LPCI SYSTEM PIPING WELD IS CRACKED
LER-81-02 ·	165884	04/03/1981	04/20/1981	C	EE	M MM	P		OA	B	S7	POTENTIAL SINGLE FAILURE IN EMERGENCY POWER SYSTEM
LER-81-03	166144	04/19/1981	05/01/1981	B	SD	OO		B	BC	G	C8	TWO CONTAINMENT INSTRUMENT ISOLATION VALVES WERE CLOSED
LER-81-04		04/21/1981	05/05/1981	D	RX	BB		B	BP	B	C4	A HIGH COOLDOWN RATE OCCURRED WHEN THE REACTOR HAD TO BE BLOWN DOWN MANUALLY
LER-81-005	166575	06/01/1981	06/17/1981	C	IA		S	B	BJ	D	N	HIGH COUNT RATE ON TWO STARTUP RANGE MONITORS
LER-81-05	165924	04/07/1981	04/30/1981	C	IB		U T	C	BB	D	N	SET POINT DRIFT IN TWO STEAM TUNNEL SWITCHES
LER-81-06	165944	04/17/1981	05/06/1981	C	MC		M	C	BB	D	N	SET POINT DRIFT IN REACTOR BUILDING RADIATION MONITOR
LER-81-07	166243	04/10/1981	05/10/1981	B	CC	OO		C	BA AQ	D	N	ONE OF SIX RELIEF VALVES FAILS TO OPEN
LER-81-08	166465	04/27/1981	06/08/1981	D	EE	M		C	BF AT	D	N	DIESEL GENERATOR TRIPS ON HIGH CRANKCASE PRESSURE DUE TO VACUUM BREAK
LER-81-09	166632	05/11/1981	06/08/1981	D	IA		M	C	BB	D	N	SET POINT DRIFT IN MAIN STEAM LINE RADIATION MONITOR

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-10	166630	05/15/1981	06/12/1981	D	SF		M T	C	EH	D	N	SET POINT DRIFT IN THREE BREAK DETECTION PRESSURE SWITCHES
LER-81-01E	167616	05/28/1981	07/02/1981	D	WE			B	BU	D	C3	HIGH COBALT AND SILVER ACTIVITY IN OYSTERS
LER-81-12	166839	06/03/1981	07/03/1981	D	CE		P	C	EH	D	N	SET POINT DRIFT IN ISOLATION CONDENSER TIME DELAY RELAY
LER-81-13	167165	06/12/1981	07/10/1981	B	SE	F		B	AQ HB	D	N	LOW STANDBY GAS TREATMENT FLOW RATE DUE TO FOULED FILTER
LER-81-15	167182	06/17/1981	07/17/1981	B	SA	FF		B	OC	H	N	CONTAINMENT AIR LOCK LEAK RATE TEST MISSED
LER-81-16	167166	06/18/1981	07/17/1981	B	IA	OO	P	C	EH	D	N	MSIV CLOSURE FAILS TO GENERATE REACTOR PROTECTION SIGNAL DUE TO RELAY DRIFT
LER-81-17	167517	06/20/1981	07/17/1981	B	SA				BU OK	A	N	TORUS OXYGEN CONCENTRATION EXCEEDED LIMIT
LER-81-02E	167613	06/22/1981	07/02/1981	B	HE	OO		B	AX	D	C3	UNMONITORED RADIOACTIVE LIQUID WASTE RELEASE
LER-81-18	167924	06/29/1981	07/27/1981	B	AD		U	C	AC	G	N	DIESEL DAY TANK FIRE DETECTOR SYSTEM FAILS
LER-81-19	167923	07/01/1981	07/27/1981	B	IA		M T	C	EH	D	N	SET POINT DRIFT IN REACTOR VESSEL HIGH PRESSURE SWITCH

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-20	168108	07/14/1981	08/06/1981	B	EE	HH OO		C	BD BA	D	C7	GAS TURBINE GENERATOR FAILS TO START DUE TO STUCK VALVE
LER-81-00S	168780		09/03/1981	B	CE	E		B	OC OK	A	N	ISOLATION CONDENSER SUPPLY LINE WELD NOT INSPECTED
LER-81-21	168111	07/10/1981	08/11/1981	B	IA		T	C	EH	D	N	SET POINT DRIFT IN CONDENSER LOW VACUUM SWITCH
LER-81-22	168555	08/10/1981	09/09/1981	D	IA	OO	P	C	EH	D	N	MSIV CLOSURE FAILS TO GENERATE REACTOR PROTECTION SIGNAL DUE TO RELAY DRIFT
LER-81-23	169053	08/10/1981	09/09/1981	B	IA		H	C	EH	D	N	MAIN STEAM LINE HI RADIATION CHANNEL TRIPS ABOVE LIMIT
LER-81-03E	168043	08/13/1981	08/24/1981	B	HC		H	B	BC OJ	B	C3	UNMONITORED RELEASE OF LIQUID EFFLUENT
LER-81-24	168935	08/17/1981	09/17/1981	B	DB		M	C	EH	D	N	SET POINT DRIFT IN REACTOR BUILDING EXHAUST DUCT RADIATION MONITOR
LER-81-25	169185	09/15/1981	09/30/1981	B	CB	DD		B	BF	B	S4	BOTH REACTOR RECIRCULATION PUMPS TRIP, ATWS WAS ISOLATED, NO ALARM
LER-81-26	169235	09/05/1981	10/05/1981	B	CE		M T	C	EH	D	N	SET POINT DRIFT IN ISOLATION CONDENSER PRESSURE SWITCH
LER-81-27	169213	09/06/1981	10/06/1981	B	SD	OO	T	C	BI EH	D	N	CONTAINMENT ISOLATION VALVE CLOSING TIME EXCEEDS LIMIT

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-28	169347	08/11/1981	10/07/1981	D	EE	F HH		C	BB BD	D	C?	BREAKER FAILS TO CLOSE CAUSING NO OUTPUT FROM GAS TURBINE
LER-81-29	169346 170103	09/08/1981	11/19/1981	B	IB		I T	C	AG	D	N	LO-LO REACTOR WATER LEVEL SWITCH STICKS
LER-81-30	169998	09/14/1981	10/13/1981	B	IA		P	C	EH	D	N	SET POINT DRIFT IN TURBINE CONTROL VALVE CLOSURE RELAYS
LER-81-31	169337	09/10/1981	10/09/1981	B	EE	F HH		C	BB BD	D	N	GAS TURBINE GENERATOR OUTPUT BREAKER FAILS TO CLOSE
LER-81-32	169307	09/25/1981	10/21/1981	B	AB	DD	P	C	BD	D	N	DIESEL FIRE PUMP FAILS TO START
LER-81-33	169609	10/06/1981	11/05/1981	B	SD		I T	C	EH	D	N	SET POINT DRIFT IN REACTOR VESSEL LO WATER LEVEL ISOLATION SWITCH
LER-81-34		10/13/1981	11/12/1981	B	IA		P	C	EH	D	N	SET POINT DRIFT IN TURBINE CONTROL VALVE BYPASS RELAY
LER-81-35	171780	11/10/1981	12/09/1981	B	IA	G		B	AP	G	N	MAIN STEAM LINE RADIATION MONITOR CHANNEL FAILS WHEN WORKERS BUMPED CABLES
LER-81-36	171790	11/12/1981	12/11/1981	B	IA		M T	C	EH	D	N	SET POINT DRIFT IN DRYWELL PRESSURE SWITCH
LER-81-38	171933	11/17/1981	12/17/1981	B	IA		M T	C	BC OJ	H	N	TURBINE CONTROL PRESSURE SWITCH LEFT ISOLATED

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-39	171599	11/24/1981	12/23/1981	B	SD		F	B	BB	E	N	RELAY FAILURE DISABLES MAIN STEAM HI FLOW ALARM
LER-81-40	171681	12/03/1981	01/03/1982	D	CE	OO X		C	BA AQ	D	N	CONTAINMENT ISOLATION VALVE MOTOR FAILS
LER-81-41	172262	12/08/1981	01/12/1982	E	EE	MM		C	AQ	D	N	GAS TURBINE GOVERNOR FAILS
LER-81-42	172808	12/15/1981	01/15/1982	B	CF	OO		B	AE	D	N	ISOLATION VALVE IN SHUTDOWN COOLING LINE INOPERABLE

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
ETS-82-03		05/04/1982	06/03/1982	D	WE			B	BU	D	N	HIGH IODINE AND SILVER ACTIVITY IN OYSTERS
ETS-82-05		08/04/1982	09/13/1982	D	WE			B	BU	D	C3	HIGH COBALT AND SILVER ACTIVITY IN OYSTERS
ETS-82-06		11/08/1982	12/16/1982	D	WE			B	BU	D	N	HIGH COBALT AND SILVER ACTIVITY IN OYSTERS
LER-82-1	172925	01/15/1982	02/22/1982	D	CC		E T	C	EN	D	N	SET POINT DRIFT ON 3 FLOW SWITCHES IN MAIN STEAM LINE
LER-82-2	172926	01/15/1982	02/22/1982	B	WA	DD		C	BC DA	G	N	EMERGENCY SERVICE WATER PUMP IS DECLARED INOPERABLE DUE TO MARINE FOULING
LER-82-3	172726	02/17/1982	03/11/1982	D	ED	LL	T	B	BD ED BY	D	C8	CONTACT IN 345KV CIRCUIT SWITCHER STICKS OPEN RESULTING IN FIRE IN SWITCHER
LER-82-4	172457	02/12/1982	03/23/1982	C	CE	E OO		C	BA GJ	H	N	CONDENSER ISOLATION VALVE STICKS CLOSED DUE TO OPERATOR ERROR
LER-82-5	172502	02/24/1982	03/23/1982	B	IA		F	B	AE AM	C	C4	CONTINUOUSLY ENERGIZED RELAYS IN REACTOR PROTECTION SYSTEM ARE FOUND MELTED
LER-82-6	172985	02/12/1982	03/25/1982	C	CD	DO OQ		C	BC BI	G	N	MAIN STEAM ISOLATION VALVE CLOSED SLOWLY DUE TO OUT OF ADJUSTMENT HYDRAULIC CYLINDER

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-82-7	172836	03/15/1982	04/05/1982	B	CE		M T	C	EN	D	N	SET POINT DRIFT CAUSES CONDENSER PRESSURE SWITCH TO TRIP TOO LOW
LER-82-8	173026	03/18/1982	04/26/1982	B	CC SH-B EB	P OO		B	AT AU	D	C4	FAILURE OF 3 BREAKERS IN A MOTOR CONTROL CENTER DUE TO WATER DAMAGE
LER-82-9	173644	04/12/1982	05/24/1982	B	SA IA		T M	C	EN	D	N	SET POINT DRIFT CAUSES DRYWELL PRESSURE SWITCH TO FAIL HIGH
LER-82-10	173617	04/13/1982	05/25/1982	B	WA SB	OO OQ		C	BA BC	D	N	VALVE IN EMERGENCY SERVICE WATER SYSTEM FAILS TO OPEN - POTENTIOMETER OUT OF ADJUSTMENT
LER-82-11	175146	05/08/1982	06/22/1982	B	EB EE	MN DG S	P	B	AT BF QA BG	D	C7 C2	UNDERVOLTAGE RELAY FOR AC LUBE PUMP SHORTED/BLEW FUSE-GAS TURBINE DECLARED INOPERABLE
LER-82-12	175230	07/02/1982	07/27/1982	B	SF-D	OO G	P	B	OK	E	N	LPCI VALVE TIMER WIRED INCORRECTLY - TIMER PREVENTS THROTTLING IN 1ST 5 MINUTES
LER-82-13	175233	06/15/1982	07/27/1982	B	ED PA	OO MN T		C	AB BA BD QA	D	C7	AIR PRESSURE REGULATING VALVE FOR GAS TURBINE FAILS DUE TO RUST IN STARTING AIR SYSTEM

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Table 8.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-82-14	175335	06/14/1982	07/27/1982	D	WA BD	BO		C	AQ FB GA	D	N	ONE EMERGENCY WATER SUPPLY PUMP HAS LOW PRESSURE DUE TO MARINE GROWTH AND MUSSELS
LER-82-15	175879	02/16/1982	09/09/1982	S	CC IA	GU	F T	C	BA BC	D	N	NO SCRAM SIGNAL ON CLOSING OF MSIV DUE TO OUT OF ADJUSTMENT LIMIT SWITCH
LER-82-16	175980	08/10/1982	09/09/1982	D	HC		M T	B	GJ	H	C7	OPERATOR FAILS TO PLACE STACK GAS MONITORING SYSTEM IN NORMAL POSITION AFTER DAILY TEST
LER-82-17	176743	08/17/1982	09/24/1982	D	EB	BU T GG		C	AB DB GA	D	C7	GAS TURBINE FAILS 2 FAST START TESTS DUE TO RUST IN AIR PRESSURE REGULATING VALVE
LER-82-18	177793	09/25/1982	10/21/1982	C	BA	T & XX		C	AD AV	C	C9	STRESS CRACK IN WELD ON CORE SPRAY SPARGERS
LER-82-19	177794	09/28/1982	10/22/1982	C	CC	GU		C	BA BB	D	C7	SET POINT DRIFT IN 5 SAFETY RELIEF VALVES
LER-82-20	180374	09/30/1982	01/10/1983	C	SS	GS		C	AY	E	N	2 HYDRAULIC SNUBBERS FAIL FUNCTIONAL TEST DUE TO LACK OF HYDRAULIC FLUID
LER-82-21	177796	09/13/1982	10/23/1982	C	EE	LL G H		C	AP AF AS	E	N	DIESEL GENERATOR TRIPS DUE TO BROKEN WIRE LUG AT CURRENT TRANSFORMER
LER-82-22	178834	09/28/1982	11/06/1982	C	HC		O	B	GJ	H	C7	OPERATOR INADVERTENTLY SECURED THE STACK-GAS RECORDER

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-82-23	184680	10/05/1982	07/06/1983	C	SD	OO		C	AU OA	D	N	LEAK RATE FOR 6 ATMOSPHERE CONTROL VALVES IS GREATER THAN TECHNICAL SPECIFICATION LIMITS
LER-82-24	179433	10/19/1982	11/29/1982	C	CD IB		E T	C	EH OA	D	N	SET POINT DRIFT OF FLOW SWITCH IN MAIN STEAM LINE
LER-82-25	179487	10/26/1982	12/03/1982	C	IA		M T	C	EH	D	N	SET POINT DRIFT CAUSES PRESSURE SWITCH IN REACTOR TRIP SYSTEM TO TRIP TOO HIGH
LER-82-26	179542	11/04/1982	12/08/1982	C	CC		U T	C	EH	D	N	SET POINT DRIFT CAUSES 6 STEAM TUNNEL TEMPERATURE SWITCHES TO TRIP TOO HIGH
LER-82-27	181506	11/11/1982	02/03/1983	C	HI		F	C	EH	D	N	SET POINT DRIFT CAUSES PRESSURE RELIEF TIME DELAY RELAYS IN BLOWDOWN LOGIC TO FAIL LONG
LER-82-28	180403	11/29/1982	01/04/1983	B	AB	G		C	AL	C	N	MISSING FIRE BARRIER IN THE CABLE VAULT AREA
LER-82-29	186233	12/07/1982	10/18/1983	B	AB	QQ JJ		B	AG OA	D	N	LOW WATER LEVEL IN 2 FIRE WATER STORAGE TANKS DUE TO FAILURE OF 2 VALVE OPERATORS

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-82-30	183922	12/13/1982	04/27/1983	D	CE SD	DO H QQ	T	C	AE BB OA	G	N	ISOLATION CONDENSER ISOLATION VALVE FAILS TO CLOSE DUE TO LUBRICANT ON LIMIT SWITCH
LER-82-31	181451	12/16/1982	01/20/1983	B	CC		H T	C	EH	D	N	SET POINT DRIFT CAUSES PRESSURE SWITCH IN MAIN STEAM LINE TO TRIP TOO HIGH
LER-82-32	181452	12/17/1982	01/25/1983	B	EE	HH T	S	C	HD OJ	H	C7	GAS TURBINE FAILS TO START DUE TO GENERATOR OVERSPEED

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
ETS-83-02		02/23/1983	05/20/1983	B	WE			B	BU	D	N	HIGH COBALT ACTIVITY IN MUSSELS
ETS-83-04		08/11/1983	10/03/1983	B	WE			B	BU	D	N	HIGH COBALT AND SILVER ACTIVITY IN OYSTERS
ETS-83-05		10/12/1983	11/10/1985	B	WE			B	BU	D	N	HIGH COBALT ACTIVITY IN AQUATIC FLORA
ETS-83-06		11/15/1983	12/22/1983	B	WE			B	BU	D	N	HIGH COBALT ACTIVITY IN OYSTERS
LER-83-1	181197	01/03/1983	02/03/1983	B	CC		M T	C	EN	D	N	SET POINT DRIFT CAUSES PRESSURE SWITCH IN MAIN STEAM LINE TO TRIP TOO LOW
LER-83-2	181224	01/04/1983	02/10/1983	B	IA	BB	M T	C	EI	G	N	PRESSURE SWITCH FOR DRYWELL PRESSURE IS OUT OF CALIBRATION
LER-83-3	182110	02/03/1983	03/14/1983	B	IA		M T	C	EN	D	N	SET POINT DRIFT CAUSES A REACTOR VESSEL PRESSURE SWITCH TO FAIL TO TRIP
LER-83-4	182111	02/07/1983	03/14/1983	B	EE	NN N		C	AQ BA ED OA	D	C7	DIESEL GENERATOR FAILS TO START DUE TO STUCK AIR START SOLENOIDS
LER-83-5	181862	02/07/1983	03/08/1983	B	CC		M T	C	EN	D	N	SET POINT DRIFT CAUSES MAIN STEAM LINE PRESSURE SWITCH TO TRIP TOO LOW

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-83-6	181863	01/25/1983	03/08/1983	D	CC		U T	C	EH	D	N	SET POINT DRIFT CAUSES A STEAM TUNNEL TEMPERATURE SWITCH TO TRIP TOO HIGH
LER-83-7	183570	02/16/1983	04/27/1983	B	CC IA	OO	F T	C	SA BC	D	N	NO SCRAM SIGNAL ON CLOSING OF MISV DUE TO AN OUT OF ADJUSTMENT LIMIT SWITCH
LER-83-8	182225	02/15/1983	03/29/1983	B	CE		M T	C	EH	D	N	SET POINT DRIFT CAUSES ISOLATION CONDENSER PRESSURE SWITCH TO TRIP TOO HIGH
LER-83-9	182398	03/07/1983	04/14/1983	B	IA		I T	C	EH	C	N	SET POINT DRIFT CAUSES REACTOR WATER LEVEL SWITCH TO TRIP TOO HIGH
LER-83-10	182597	03/24/1983	04/27/1983	B	CD	OO		C	BI	G	N	MSIV CLOSES TOO SLOWLY DUE TO TIGHT PACKING AROUND THE VALVE STEM
LER-83-11	185473	03/15/1983	04/22/1983	B	HA IA	HN OC	F	C	BI EH	D	N	SET POINT DRIFT CAUSES TIME DELAY RELAY THAT BYPASSES TURBINE SCRAM TO FAIL LONG
LER-83-12	188837	03/26/1983	01/30/1984	D	SF-B SF-D	OO	T	B	OJ	H	N	VALVE PERMISSIVE INTERLOCK SWITCH FOR LPCI/CS NOT RETURNED TO SERVICE AFTER TEST

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-83-13	183025	03/24/1983	04/28/1983	B	CH	DD OO		B	BF OK	H	N	REACTOR FEED AND BOOSTER PUMPS TRIP DUE TO LOW SUCTION FLOW
LER-83-14	185711	03/31/1983	08/16/1983	D	EE	MM		C	AB BD	G	C7	THE GAS TURBINE GENERATOR FAILS TO START DUE TO FAILURE OF BOTH IGNITORS
LER-83-15	182861	04/11/1983	05/23/1983	B	HA IA	MM OO	P	C	BI EH	D	N	SET POINT DRIFT CAUSES TIME DELAY RELAY THAT BYPASSES TURBINE TRIP TO FAIL LONG
LER-83-16	183101	05/02/1983	06/03/1983	B	IA		R T	C	EH	D	N	SET POINT DRIFT CAUSES A REACTOR VESSEL HIGH PRESSURE SWITCH TO TRIP TOO HIGH
LER-83-17	183102	05/02/1983	06/03/1983	B	IA		R T	C	EH	D	N	SET POINT DRIFT CAUSES REACTOR LOW PRESSURE SWITCH TO TRIP TOO HIGH
LER-83-18	183935	05/17/1983	07/01/1983	B	EE	T MM		C	AA BI	D	C7	GAS TURBINE FAILS TO REACH READY TO LOAD STATUS DUE TO WORN IGNITOR
LER-83-19	183149	05/03/1983	06/17/1983	B	IA		R T	C	EH	D	N	SET POINT DRIFT CAUSES REACTOR LOW PRESSURE SWITCH TO TRIP TOO HIGH

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-83-20	103936	06/07/1983	07/01/1983	D	HG	OO Z Q		B	AI ND AO	D	N	CRACKED WELD ON WELDOLET THAT SUPPORTS A RELIEF VALVE IN THE CLEANUP SYSTEM
LER-83-21	103937	05/17/1983	06/27/1983	B	HA IA	NN OO	F	C	BI BI OK	G	C7	2 TIME DELAY RELAYS FAIL LONG DUE TO IMPROPER CALIBRATION - 5 EVENTS SINCE 1978
LER-83-22	104080	06/03/1983	07/11/1983	B	HA IA	NN OO	F	C	BI BI OK	G	C7	TIME DELAY RELAY FAILS LONG DUE TO IMPROPER CALIBRATION
LER-83-23	104570	06/16/1983	07/19/1983	B	CC	OO		B	OC	A	N	2 ACOUSTICAL VALVE MONITOR TESTS NOT PERFORMED DUE TO RECORDS ERROR
LER-83-24	104571	06/12/1983	07/19/1983	B	EE	T X DD NN		B	AA OA	D	N	GAS TURBINE GENERATOR WAS DECLARED INOPERABLE DUE TO A FAILED EGR OIL PUMP MOTOR
LER-83-25	105304	07/12/1983	08/25/1983	B	EE	S T NN		C	BD BG OA OJ	G	N	GAS TURBINE GENERATOR IS DECLARED INOPERABLE DUE TO BLOWN FUSE DURING CALIBRATION
LER-83-26	105712	08/16/1983	09/23/1983	E	EE	C T NN		C	AC BE BF	D	C7	GAS TURBINE GENERATOR SHUT DOWN DUE TO AN OIL IMPREGNATED CABLE

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-83-27	186130	08/29/1983	10/25/1983	B	CB	R	F	C	EH	D	N	SET POINT DRIFT CAUSES TIME DELAY RELAY FOR ISOLATION CONDENSER TO FAIL LONG
LER-83-28	186690	09/30/1983	11/03/1983	B	DD		R C	B	BE ED	D	N	1 CHANNEL OF OFF-GAS RADIATION MONITOR IS DECLARED INOPERABLE DUE TO SHORTED RESISTOR
LER-83-29	187370	11/08/1983	12/01/1983	B	IA SA		M T	B	EH	D	N	SET POINT DRIFT CAUSES 2 DRYWELL HIGH-PRESSURE SWITCHES TO TRIP TOO HIGH
LER-83-30	187710	08/16/1983	12/13/1983	B	SA CC	GD		B	AV OA	D	N	MAIN STEAM DRAIN VALVE IS DECLARED INOPERABLE DUE TO STEM PACKING LEAK
LER-83-31	187719	11/04/1983	12/13/1983	B	DD ID		N T	B	AG OA	D	CD	1 CHANNEL OF APRM IS DECLARED INOPERABLE DUE TO A FAILED SWITCH
LER-83-32	187930	11/25/1983	01/04/1984	B	CB SA	DD PP		B	AA AG	D	N	REACTOR COOLANT LEAK RATE EXCEEDS LIMIT DUE TO A FAILED SEAL ON RECIRCULATION PUMP

Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-83-33	187931	11/26/1983	01/04/1984	D	SH-D	V	P	B	AL BD	E	N	1 TRAIN OF STANDBY GAS TREATMENT IS DECLARED INOPERABLE DUE TO LOOSE SCREW
LER-83-34	188117	12/05/1983	01/10/1984	B	EB	O LL		B	AT AL OA	G	N	RESERVE STATION SERVICE TRANSFORMER HAS OIL LEAK DUE TO LOOSE BOLTS
LER-83-35	188118	12/09/1983	01/10/1984	B	EB	D LL		B	AQ OA	D	N	RESERVE STATION SERVICE TRANSFORMER HAS SALT CONTAMINATION OF BUSHINGS

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-84-3	190282	02/13/1984	03/16/1984	B	BA		N	B	OD		N	GAMMA SCAN OF 2 OYSTERS SHOWS HIGH LEVELS OF AG-110M
LER-84-5	189594	04/14/1984	05/08/1984	C	CD	OO		C	AT	D	N	COMBINED LEAK RATE OF MSIV'S IS HIGHER THAN MAXIMUM ALLOWED FOR SINGLE MSIV
LER-84-6	189650	04/18/1984	05/22/1984	C	IB		C	B	EF	G	N	REACTOR SCRAM DUE TO ELECTRONIC NOISE SPIKE CAUSED BY MAINTENANCE ACTIVITIES
LER-84-7	191540	04/09/1984	05/16/1984	B	BA		N	B	OD		N	ROUTINE GAMMA SCAN SHOWS HIGH LEVEL OF CO-60 IN AQUATIC FLORA
LER-84-8	190244	04/27/1984	05/30/1984	C	SF-D CB CG	I		C	AO	E	C4	3 WELDS HAVE INTERGRANULAR STRESS CORROSION CRACKING
LER-84-9	190245	04/25/1984	05/30/1984	C	SS	GG		C		D	N	HYDRAULIC SNUBBER FAILS BLEED RATE TENSION AND COMPRESSION TEST
LER-84-11	190466	05/27/1984	07/03/1984	D	AB PA		T	C	BD BK OA		C8	2 FIRE DETECTOR STRINGS IN CONDENSER BAY FAIL DUE TO LOW SUPERVISORY AIR PRESSURE
LER-84-12	190646	06/14/1984	07/20/1984	D	CC	FF OO		C	AO BA ON	G	C7	SET POINT DRIFT CAUSES 3 SAFETY RELIEF VALVES TO FAIL TO OPEN
LER-84-14	190978	07/09/1984	08/07/1984	B	CE	H X OO	K T	C	BA BC	G	C7	ISOLATION VALVE FOR ISOLATION CONDENSER FAILS CLOSED DUE TO LIMIT SWITCH

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Table B.1 Reportable events for Millstone 1 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-84-17	191288	08/02/1984	08/29/1984	B	CB IA	CO		B	AU	G	N	REACTOR SHUT DOWN DUE TO LEAK IN STOP VALVE ON RECIRCULATION RISER
LER-84-18	191140	08/03/1984	09/10/1984	D	CE	F H X OO	K T	C	BA BC BY	G	C7	ISOLATION VALVE FOR ISOLATION CONDENSER FAILS CLOSED - SECOND FAILURE IN ONE MONTH

Table B.2. Plant status, component status, and cause of reportable events

Code	Plant status	Component status	Cause of reportable event
A	Construction	Maintenance and repair	Administrative error
B	Operation	Operation	Design error
C	Refueling	Testing	Fabrication error
D	Shutdown		Inherent error
E			Installation error
F			Lightning
G			Maintenance error
H			Operation error
I			Weather

Table B.3. Systems involved with reportable events

System	Code
Reactor	RX
Reactor vessel internals	RA
Reactivity control systems	RB
Reactor core	RC
Reactor coolant and connected systems	CX
Reactor vessels and appurtenances	CA
Coolant recirculation systems and controls	CB
Main steam systems and controls	CC
Main steam isolation systems and controls	CD
Reactor core isolation cooling systems and controls	CE
Residual heat removal systems and controls	CF
Reactor coolant cleanup systems and controls	CG
Feedwater systems and controls	CH
Reactor coolant pressure boundary leakage detection systems	CI
Other coolant subsystems and their controls	CJ
Engineered safety features	SX
Reactor containment systems	SA
Containment heat removal systems and controls	SB
Containment air purification and cleanup systems and controls	SC
Containment isolation systems and controls	SD
Containment combustible control systems and controls	SE
Emergency core cooling systems and controls	SF
Core reflooding	SF-A
Low-pressure safety injection system and controls	SF-B
High-pressure safety injection system and controls	SF-C
Core spray system and controls	SF-D
Control room habitability systems and controls	SG
Other engineered safety feature systems and their controls	SH
Containment purge system and controls	SH-A
Containment spray system and controls	SH-B
Auxiliary feedwater system and controls	SH-C
Standby gas treatment systems and controls	SH-D
Instrumentation and controls	IX
Reactor trip systems	IA
Engineered safety feature instrument systems	IB
Systems required for safe shutdown	IC
Safety-related display instrumentation	ID
Other instrument systems required for safety	IE
Other instrument systems not required for safety	IF

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Table B.3 (continued)

System	Code
Electric power systems	EX
Offsite power systems and controls	EA
AC onsite power systems and controls	EB
DC onsite power systems and controls	EC
Onsite power systems and controls (composite ac and dc)	ED
Emergency generator systems and controls	EE
Emergency lighting systems and controls	EF
Other electric power systems and controls	EG
Fuel storage handling systems	FX
New fuel storage facilities	FA
Spent-fuel storage facilities	FB
Spent-fuel pool cooling and cleanup systems and controls	FC
Fuel handling systems	FD
Auxiliary water systems	WX
Station service water systems and controls	WA
Cooling systems for reactor auxiliaries and controls	WB
Demineralized water makeup systems and controls	WC
Potable and sanitary water systems and controls	WD
Ultimate heat sink facilities	WE
Condensate storage facilities	WF
Other auxiliary water systems and controls	WG
Auxiliary process systems	PX
Compressed air systems and controls	PA
Process sampling systems	PB
Chemical, volume control, and liquid poison systems and controls	PC
Failed-fuel detection systems	PD
Other auxiliary process systems and controls	PE
Other auxiliary systems	AX
Air conditioning, heating, cooling, and ventilation systems and controls	AA
Fire protection systems and controls	AB
Communication systems	AC
Other auxiliary systems and controls	AD
Steam and power conversion systems	HX
Turbine-generators and controls	HA
Main steam supply systems and controls (other than CC)	HB
Main condenser systems and controls	HC
Turbine gland sealing systems and controls	HD

Table B.3 (continued)

System	Code
Turbine bypass systems and controls	HE
Circulating water systems and controls	HF
Condensate cleanup systems and controls	HG
Condensate and feedwater systems and controls (other than CH)	HH
Steam generator blowdown systems and controls	HI
Other features of steam and power conversion systems (not included elsewhere)	HJ
Radioactive waste management systems	MX
Liquid radioactive waste management systems	MA
Gaseous radioactive waste management systems	MB
Process and effluent radiological monitoring systems	MC
Solid radioactive waste management systems	MD
Radiation protection systems	BX
Area monitoring systems	BA
Airborne radioactivity monitoring systems	BB
Other	XX
Not applicable	ZZ

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Table B.4. Equipment and instruments involved in reportable events

Code		Code	
		Equipment	
A	Accumulator	W	Internal combustion engine
B	Air drier	X	Motor
C	Battery and charger	Y	Nozzle
D	Bearing	Z	Pipe and pipe fitting
E	Blower and dampers	AA	Power supply
F	Breaker	BB	Pressure vessel
G	Cables and connectors	CC	Pressurizer
H	Condenser	DD	Pump
I	Control rod	EE	Recombiner
J	Control rod drive	FF	Seal
K	Cooling tower	GG	Shock absorber
L	Crane	HH	Solenoid
M	Demineralizer	II	Steam generator
N	Diesel generator	JJ	Storage container
O	Fastener	KK	Support structure
P	Filter/screen	LL	Transformer
Q	Flange	MM	Tubing
R	Fuel element	NN	Turbine
S	Fuse	OO	Valve
T	Generator	PP	Valve, check
U	Heat exchanger	QQ	Valve operator
V	Heater		
		Instrumentation	
A	Alarm	L	Power range instrument
B	Amplifier	M	Pressure sensor
C	Electronic function unit	N	Radiation monitor
D	Failed fuel detection instrument	O	Recorder
E	Flow sensor	P	Relay
F	In-core instrument	Q	Seismic instrument
G	Indicator	R	Solid state device
H	Intermediate range instrument	S	Start-up range instrument
I	Level sensor	T	Switch
J	Meteorological instrument	U	Temperature sensor
K	Position instrument		

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Table B.5. Abnormal conditions of reportable events

	Mechanical
AA	Normal wear/aging/end of life: expected effect of normal usage
AB	Excessive wear/clearance: component (especially a moving component) experiences excessive wear or too much clearance or gap exists because of overuse, lack of lubrication
AC	Deterioration/damage: component is no longer at an acceptable level of quality (e.g., high temperature causes rubber seals to chemically break down or deteriorate, insulation breaks down)
AD	Break/shear: structural component physically breaks apart (not when something "breaks down")
AE	Warp/bend/deformation: shape of component is physically distorted
AF	Collapse: tank or compartment has an external pressure exerted that results in deformation
AG	Seize/bind/jam: component has inhibited movement caused by crud, foreign material, mechanical bonding, another component
AH	Excessive mechanical loads: mechanical load exceeds design limits
AI	Mechanical fatigue: failure due to repeated stress
AJ	Impact: the result of the force of one object striking another
AK	Improper lubrication: insufficient or incorrect lubrication
AL	Missing/loose: component is missing from its proper place or is loose or has undesired free movement
AM	Wrong part: incorrect component installed in a piece of equipment
AN	Wrong material: incorrect material used during fabrication or installation
AO	Weld-related failure: failure caused by defective weld or located in the heat-affected zone
AP	Vibration other than flow induced: vibration from any cause other than fluid flow
AQ	Crud buildup: buildup of foreign material such as dust, sticks, trash (not corrosion or boron precipitation)
AR	Corrosion/oxidation: unanticipated attack
AS	Dropped: component is dropped (includes control rod that is "dropped" into core)
AT	Leak, internal, within system: leak from one part of a system to another part of the same system
AU	Leak, internal, between systems: leak from one system to a different system
AV	Crack: defect in a component does not result in a leak through the wall
AW	Leak, external: defect in a component results in a leak from the system that is contained in an onsite building
AX	Leak to environment: leak not resulting from a cracked or broken component
AY	Was opened/transfers open: component is/was opened by error or spuriously opens

Table B.5 (continued)

AZ	Was closed/transferred closed: component is/was wrongly closed by error or spuriously closes
BA	Fails to open: component is in the closed state and fails to open on demand (e.g., the circuit breaker "fails to open" when an overcurrent occurs)
BB	Fails to close: component is in the open state and fails to close on demand
BC	Malposition or maladjustment: component is out of desired position (e.g., normally open valve is closed) or adjusted improperly (not for instrument drift or out of calibration)
BD	Failure to start/turn on: component fails to start on demand
BE	Stopped/failed to continue to run: component fails to continue running when it has previously started
BF	Tripped: component automatically trips on or off (desired or undesired) (e.g., the turbine tripped because of overspeed, the circuit breaker tripped because of overspeed, or the circuit breaker tripped because of overload)
BG	Deenergized/power removed: component on system loses its driving potential but not necessarily electrical power [e.g., (1) a fuse blows and there is no power to a sensor, and the sensor is deenergized; (2) a valve closes off the steam supply to a turbine, and the turbine has no driving power]
BH	Energized/power applied: component or system gains its driving potential but not necessarily electrical power (e.g., valve is opened allowing steam to turn a turbine)
BI	Unacceptable response time: component does not respond to a demand within a desired time frame but does not otherwise fail (e.g., a diesel generator fails to come to full speed within the time constraint)
BJ	High pressure: higher than normal or desired pressure exists in a component or system (does not include instrument misindications)
BK	Low pressure: lower than normal or desired pressure exists in a component or system (does not include instrument misindication)
BL	High temperature: component experiences a higher than normal or desired temperature
BM	Low temperature: component (or system) experiences a lower than normal or desired temperature
BN	Freezing: fluid medium (e.g., water) freezes in or on a component
BO	Excessive thermal cycling: frequent changes in temperature that could result in metal fatigue or cracking
BP	Unacceptable heatup/cooldown rate: heatup or cooldown rate exceeds limits
BQ	Thermal transient: system experiences an undesired or unstable thermal transient or thermal change
BR	Excessive number of pressure cycles: system experiences an undesired number of significant pressure changes (e.g., pressure pulses as from a positive displacement pump)

Table B.5 (continued)

BS	High level/volume: higher than normal or desired level or volume exists (actual or potential) in a component, such as tank or sump, or area, such as auxiliary building (not for instrument misindication)
BT	Low level/volume: lower than normal or desired level or volume exists in a component (not for instrument misindication)
BU	Abnormal concentration/pH: an abnormal (either high or low) concentration of a chemical or reagent exists in a fluid system or an abnormal pH exists (does not include abnormal boron concentration)
BV	Abnormal boron concentration: process system control rod has an abnormal boron concentration from burnup, dilution, or overaddition
BW	Overspeed: speed in excess of design limits
BX	Cladding failure: cladding of a component fails (e.g., the cladding of a fuel pellet is breached, and radioactive fuel leaks out)
BY	Burning/smoking: component is on fire or smoking
BZ	Engaged: component engages or meshes (this is not to be used when a component binds or becomes stuck or jammed)
CA	Disengaged/uncoupled: component disengages, loses required friction, or is no longer meshed (as in gears), for example, the clutch on the motor disengages from the shaft (this should not be used for dropped control rods)
	Electric/instruments
EA	Excessive electrical loads: electrical loads exceed design rating
EB	Overvoltage/undercurrent: component failure produces an overvoltage/undercurrent condition other than open circuits
EC	Undervoltage/overcurrent: component failure produces an undervoltage/overcurrent condition other than shorts
ED	Short circuit/arcing/low impedance: electrical component shorts or arcs in the circuit or has a low impedance including shorts to ground
EE	Open circuit/high impedance/bad electrical contact: electrical component has a structural break, or electrical contacts fail to contact and fail to pass the desired current
EF	Erratic operation: component (especially electrical or instrument) behaves erratically or inconsistently (if an instrument produces a bad but constant signal, use "EG", if an instrument produces an inconsistent signal use "EF")
EG	Erroneous/no signal: electrical component or instrument produces an erroneous signal or gives no signal at all (not for out-of-calibration error)
EH	Drift: a change in a setting caused by aging or change of physical characteristics (does not include personnel errors or a physical shift of a component)

Table B.5 (continued)

EI	Out of calibration: component (particularly instruments) become out of adjustment or calibration (does not include drift)
EJ	Electromagnetic interference: abnormal indication or action resulting from unanticipated electromagnetic field
EK	Instrument snubbing: dampening of pulsating signals to an instrument

Hydraulic

HA	High flow: higher than normal or desired flow exists in a component/system (does not include instrument misindication) (see code EG)
HB	Low flow: lower than normal or desired flow exists in a component/system (does not include instrument misindication)
HC	No flow or impulse: fluid flowing through a pipe, filter, orifice, or trench or the fluid in an impulse line (e.g., instrument sensing line) is blocked completely or decreased due to some foreign material, crud, closed (either partially or completely) valve or damper, or insufficient flow area
HD	Flow induced vibration
HE	Cavitation
HF	Erosion
HG	Vortex formation
HH	Water hammer
HI	Pressure pulse/surge
HJ	Air/steam binding
HK	Loss of pump section
HL	Boron precipitation

Other

OA	Declared inoperable: component or system is declared inoperable as required by Technical Specifications but may be capable of partially or completely performing its desired duties when requested (a component/system that is completely failed should not use this code)
OB	Flux anomaly: flux characteristics of the reactor core are not as required or desired (e.g., flux spike due to xenon burnout)
OC	Test not performed: operator or test personnel fails to perform a required test within the required period
OD	Radioactivity contamination: component, system, or area becomes more radioactive than desired or expected
OE	Temporary modification: an installation intended for short term use (usually this is for maintenance or modification of installed equipment)
OF	Environmental anomaly
OG	Airborne release
OH	Waterborne release
OI	Operator communication
OJ	Operator incorrect action
OK	Procedure or record error

Table B.6. Significance Criteria for reportable events - Significant

Category of significance	Event description
S1	Two or more failures occur in redundant systems during the same event
S2	Two or more failures due to a common cause occur during the same event
S3	Three or more failures occur during the same event
S4	Component failures occur that would have easily escaped detection by testing or examination
S5	An event proceeds in a way significantly different from what would be expected
S6	An event or operating condition occurs that is not enveloped by the plant design bases
S7	An event occurs that could have been a greater threat to plant safety with (1) different plant conditions, (2) the advent of another credible occurrence, or (3) a different progression of occurrences
S8	Administrative, procedural, or operational errors are committed that resulted from a fundamental misunderstanding of plant performance or safety requirements
S9	Other (explain)

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Table B.7. Significance criteria for reportable events — Conditionally Significant

Category of conditional significance	Event description
C1	A single failure occurs in a nonredundant system
C2	Two apparently unrelated failures occur during the same event
C3	A problem results in an offsite radiation release or exposure to personnel
C4	A design or manufacturing deficiency is identified as the cause of a failure or potential failure
C5	A problem results in a long outage or major equipment damage
C6	An engineering safety feature actuation occurs during an event
C7	A particular occurrence is recognized as having a significant recurrence rate
C8	Other (explain)

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APPENDIX C

STAFF REVIEW OF PSA

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REVIEW OF RISK BASED EVALUATION OF INTEGRATED SAFETY ASSESSMENT PROGRAM (ISAP) ISSUES FOR MILLSTONE UNIT 1

FINAL REPORT

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1.0 INTRODUCTION

The Integrated Safety Assessment Program (ISAP) was developed by NRC to examine the outstanding issues from several NRC programs that are pertinent to each power plant and assess the importance of each issue with respect to its impact on the risk associated with the operation of the plant. The issues that will be considered for each plant in this program include those identified in Phase II of the Systematic Evaluation Program (SEP), pending licensing requirements for the particular facility including TMI Action Plan items, pending Unresolved and Generic Safety Issues, significant events that have occurred during the operation of the plant, and dominant contributors to plant risk based on a plant-specific Probabilistic Safety Analysis (PSA). An initial screening of the issues required by the programs mentioned above is performed to arrive at a set of ISAP topics that are appropriate for the specific plant under study. A detailed evaluation of these topics is then performed by the licensee and submitted to the NRC for review. The NRC's analysis of each topic consists of a review of the licensee's submittal, comparison of the plant design and procedures with current licensing criteria, and assessment of the risk significance of each topic for the plant under study.

The first plant being evaluated under this program is Northeast Utilities' Millstone Unit 1, a 660 MWe boiling water reactor. For this plant, a level 1 Probabilistic Risk Assessment (PRA) had previously been performed as a part of the Interim Reliability Evaluation Program (IREP)(1). This PRA has recently been revised by Northeast Utilities by including design and procedural changes that have taken place since the original IREP study and by updating the appropriate initiating events, component failure rates, test and maintenance frequencies and recovery action probabilities(2). In addition, the licensee has evaluated some of the ISAP topics using PRA techniques.

The objective of the present study is to identify and resolve significant differences between the IREP and ISAP probabilistic risk assessments (referred to in this report as the IREP study and the ISAP study), identify the areas of plant vulnerability, review those topics which were analyzed by the licensee using PRA techniques, and rank the topics with respect to their impact on the safety of the plant.

It is important to note that due to limitations in time and level of effort, the review of the ISAP study is not performed in the traditional sense of a PRA review. Rather, it is done by comparing the results of each major section of this study with the results of the IREP study. Using this comparison, significant differences between the two studies are identified, and the effect of these differences on the dominant accident sequences and overall core melt frequency are analyzed.

In the next section, a comparison between the ISAP and IREP probabilistic risk assessments will be presented. This will consist of comparing the initiating events, event tree analyses, component and system reliability analyses and the human reliability analyses. The comparison between the results of the two studies, insights into major contributors to the core melt frequency, and areas of plant vulnerability is presented in Section 3.0. Section 4.0 contains a review of alternative methods for ranking the importance of a safety-related issue and proposes a ranking scheme that would be best suited for prioritization of the importance of the ISAP topics. This section also includes the results of the review of those ISAP topics that were analyzed by the licensee using PRA techniques. The review of ISAP topics includes comments on the validity of the utility's analysis and ranking of each topic based on our proposed ranking scheme. Finally, all the references cited in this report are listed in Section 5.0.

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2.0 BRIEF REVIEW OF THE MILLSTONE UNIT 1 PROBABILISTIC SAFETY STUDY (PSS)

In this section a brief review of the Millstone Unit 1 PSS performed by the licensee as a part of the ISAP study will be presented. As was discussed earlier, due to limitations in time and level of effort this review is not performed in the same manner as a traditional detailed PRA review. Rather, it is done by examining the major segments of the PSS for its accuracy in procedures, assumptions, modeling, use of data, and by comparing the results of each of these major segments with the results found in the earlier IREP study.

The major segments of the PSA reviewed and presented in this section include the initiating events, event tree analysis, component and system reliability analysis and human reliability analysis. A review of the results and insights into major contributors to the core melt frequency is presented in Section 3.0.

2.1 Initiating Events

The initiating events in both the ISAP and IREP studies were grouped in two broad categories of LOCAs (including interfacing system LOCAs) and transients due to anticipated initiators and support system initiators. Each of these broad groups was further divided into subgroups based on the systems required for mitigation of the initiators. A comparison between the initiator categories and frequencies used in the two studies follows.

2.1.1 LOCA Initiators

In the IREP study the LOCA initiators were grouped into two classes, steam line breaks and liquid line breaks. Each of these classes was further categorized by three break sizes. Table 2.1 shows the LOCA classes, approximate break diameters, systems required for mitigation of these initiators, and frequencies assigned to each initiator. As seen in this table, the major reason for differentiating between the steam line and liquid line breaks is the difference in the systems required for mitigation of the same break sizes. For the small break LOCA, the mitigating systems are the same for the two classes. For the intermediate steam line break, the break would occur above the core level. This will result in an increase

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Table 2.1 IREP LOCA Initiators

LOCA Class	Approximate Break Diameter (inches)	Systems Required for Mitigation	Frequency (Events Per Yr)
1. Small Steam Break (SSB)	$D \leq 5.41$	Feedwater OR ADS* & LPCI OR ADS & Core Spray	10^{-3}
2. Intermediate Steam Break (ISB)	$5.41 \leq D \leq 5.90$	Feedwater OR LPCI OR ADS & Core Spray	10^{-4}
3. Large Steam Break (LSB)	$5.90 \leq D \leq 20.08$	Feedwater OR LPCI OR Core Spray	10^{-4}
4. Small Liquid Break (SLB)	$D \leq 5.24$	Feedwater OR LPCI OR ADS & Core Spray	10^{-3}
5. Intermediate Liquid Break (ILB)	$5.24 \leq D \leq 6.05$	Feedwater OR ADS & LPCI OR Core Spray	10^{-4}
6. Large Liquid Break (LLB)	$6.05 \leq D \leq 32.60$	LPCI OR Core Spray	10^{-4}

* Automatic Depressurization System

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in the upward flow of steam, inhibiting the core spray system from providing sufficient downward coolant flow to cover the core. Thus, the reactor coolant system (RCS) must be depressurized before the core spray system is effective. This is not true for the Low Pressure Coolant Injection (LPCI) system which injects into the core from a low vessel level. Thus, the LPCI system can, without depressurization, cover the core. The situation is reversed in the case of an intermediate liquid break. In this case, because the break area is below the core level, the flow out of the core is downward and the core spray function is not inhibited. However, the LPCI system cannot provide the required mitigation function due to slower vessel pressure reduction and flow diversion from the liquid break area unless the RCS is depressurized.

In the case of large LOCA, for the large liquid break, there is too much diversion of the flow out of the break area to make the feedwater system an effective mitigating system, whereas in the case of a large steam break, the feedwater system is an effective mitigating system.

In the ISAP study, the steam and liquid line breaks are not separated. The various break sizes in this study are categorized into four classes of LOCAs as shown in Table 2.2. The most noticeable difference between the two studies is inclusion in ISAP of a small-small break LOCA with equivalent diameter of greater than 2.5 gallons per minute (gpm) leak (Technical Specification shutdown limit) up to 1.35 inches in diameter. The initiating frequency of this class of LOCA is estimated to be an order of magnitude larger than the small break LOCA. In the lower range of this new small-small break category, manual shutdown would be necessary whereas automatic trip will occur at the higher range. In addition, at the lower range of this break, automatic depressurization by the Automatic Depressurization System (ADS) might not occur due to lack of high pressure in the drywell necessary for the initiation of ADS. Thus, manual depressurization (MD) would be necessary in these situations.

Another difference between the two studies is that the inadvertent opening of safety/relief valves is classified in the ISAP as a LOCA initiator whereas this event was classified as a transient initiator in the IREP. This classification should not have any effect on the actual sequence of events that are delineated for this initiator.

Table 2.2 ISAP LOCA Initiators

LOCA Class	Approximate Break Diameter (inches)	Systems Required for Mitigation	Frequency
1. Small-Small	$2.5\text{gpm} \le D \le 1.35$	Main Feedwater (No Trip) OR Feedwater (Trip) OR ADS/MD & LPCI OR ADS/MD & Core Spray	10^{-2}
2. Small	$1.35 \le D \le 6.05$	ADS & LPCI OR ADS & Core Spray	10^{-3}
3. Inadvertent Operation of Safety/Relief Valve	$1.35 \le D \le 6.05$	Main Feedwater	2.02×10^{-2}
4. Large LOCA	$6.05 \le D$	LPCI & Core Spray	10^{-4}

Overall, the most important difference between the two studies in the classification of LOCAs, is the creation of a small-small break LOCA in the ISAP study. This class of LOCA with a relatively large initiation frequency and some unique mitigation requirements, has a significant contribution to the ISAP core melt frequency. This will be discussed in Section 3.0 on the overall results. In the case of intermediate and large LOCA's, the major difference between the two studies is the differentiation of liquid and steam break lines. Without this differentiation, the assumptions for systems required for mitigation of a break size might be somewhat more conservative. Finally, in the case of inadvertent opening of safety/relief valves, the difference between the two studies is the initiator frequency used for this event which is an order of magnitude smaller in the ISAP study due to replacement of the safety/relief valves with a new set of more reliable valves.

2.1.2 Consideration of Interfacing System LOCAs

In the IREP study, the interfacing system LOCAs were not considered explicitly. The justification for not considering these events was that in the WASH-1400 study (3), the interfacing system LOCAs were not found to be important to risk for BWRs. The Millstone Unit 1 interfacing systems were compared with the Peach Bottom plant analyzed in WASH-1400, and since the systems were similar, no further analysis of these initiators was conducted.

In the ISAP study, five systems interfacing with the primary system were considered in detail for the possibility of initiation of LOCAs. These are the Isolation Condenser, the Shutdown Cooling System, the Reactor Water Cleanup System, the Low Pressure Coolant Injection System, and the Core Spray System. Of these systems, the Shutdown Cooling System was eliminated from further consideration because only multiple catastrophic failures could create an interfacing LOCA. For the other systems, simple fault trees were used to estimate the frequency of occurrence of unmitigated LOCAs due to interfacing system failure that would lead to a core meltdown. Table 2.3 shows the unmitigated interfacing system LOCAs, their frequencies, and their contribution to the total core melt frequency. As can be seen from these results, the contribution of interfacing system LOCAs to the overall core melt frequency is negligible.

Table 2.3 ISAP Interfacing System LOCA Event Frequencies

Event	Frequency (per year)	Percentage of Total Core Melt Frequency
1. Unmitigated Isolation Condenser Tube Rupture	1.5E-7	0.02
2. Unisolated LOCA in the Core Spray System	1.1E-7	0.014
3. Interfacing System LOCA in the LPCI System	1.61E-8	0.002
4. Unisolated LOCA in the RWCU System	1.39E-8	0.001

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2.1.3 Transient Initiators

Two major classes of transients were considered in the ISAP study. These are the anticipated transients and special initiators that result from support system failures. The anticipated transients in this study are grouped into the following five categories:

1. Reactor Transients with Power Conversion System Available
2. Reactor Transients with Power Conversion System Unavailable
3. Reactor Trip Events
4. Loss of Feedwater Events
5. Loss of Normal Power Events.

The first category of transients in the ISAP study is similar to Category T1, "Most Transients", in the IREP study. Table 2.4 shows the list and frequency of transient initiators in this category used in these studies. The initiator frequencies in the ISAP study were calculated by performing Bayesian updating of the plant-specific data. For the prior distributions, the results of industry experience compiled in the EPRI report EPRI-NP-2230(4) were used. In developing the prior distributions from this source, the data on the first two years of each plant's operation were discarded so that the trips during the startup period would not be included. The data were then fit into a Gamma distribution. Having these prior distributions, the posterior distributions for each initiator were developed by updating the plant-specific initiators.

Looking at Table 2.4, it can be seen that 16 out of 18 top initiators are the same in both categories. Initiators 3 and 11 included in this ISAP category were included in the "transient with power conversion system unavailable" category in the IREP study. Also, initiators 24 to 27 in the ISAP study were included in a new category of "reactor trip events." The mitigating systems required for this category are exactly the same as Category 1. The frequency of these initiators in the ISAP study is shown in Table 2.5.

To get an idea of the effect of the Bayesan updating on the initiator frequencies, we can compare the total frequency of the 19 common initiators
Insert Table 2.4

Table 2.4 Comparison Between ISAP and IREP Initiator Frequencies Included in the "Reactor Transients With Power Conversion System Available"- Category 1

Initiator	Frequencies (per year) ISAP (Plant Specific)	IREP (NP-801)
1. Electrical Load Rejection	0.386	1.04
2. Turbine Trip	0.742	1.41
3. Pressure Regulator Fails Open	0.165	Included in Category 2; see Table 2.6
4. Pressure Regulator Fails Closed	0.009	0.14
5. Turbine Bypass Valve Fails Open	0.089	0.04
6. Recirculation Flow Control Fails (Increasing)	0.011	0.24
7. Recirculation Flow Control Fails (Decreasing)	0.006	0.06
8. Trip on One Recirculation Pump	0.345	0.02
9. Trip of All Recirculation Pumps	0.093	0.06
10. Recirculation Pump Seizure	0.000	ε
11. Feedwater Flow Control Failure (Increasing)	0.444	Included in Category 2; see Table 2.6
12. Feedwater Flow Control Failure (Decreasing)	0.630	0.43
13. Loss of a Feedwater Heater	0.004	
14. Loss of All Feedwater Heaters	0.096	0.02
15. Trip of One Feedwater/Condensate Pump	0.176	0.2
16. Inadvertent Control Rod Withdrawal	0.003	ε
17. Inadvertent Control Rod Insertion	0.008	0.1
18. Partial MSIV Closure	Included in Category 2; see Table 2.6	0.04
19. Control Valves Fail Closed	0.023	0.51
20. Abnormal Startup of Idle Recirc Pump	ε	ε
21. Low Feedwater During Startup or Shutdown		0.35
22. High Feedwater During Startup or Shutdown		0.10
23. High Flux Due to Rod Withdrawal at Startup		0.04
24. Scram Due to Plant Occurrences	Included in Category 3; see Table 2.5	0.35
25. Spurious Trip Via Instrumentation, RPS Fault	Included in Category 3; see Table 2.5	1.16
26. Manual Scram is Out of Tolerance Condition	Included in Category 3; see Table 2.5	0.27
27. Detected Faults in RPS	Included in Category 3; see Table 2.5	0.02
28. Cause Unknown	----	0.02

Table 2.5 Comparison Between ISAP and IREP Initiator Frequencies Included in the "Reactor Trip Events" - Category 3

Initiator	Frequencies (Per year) ISAP (Plant-Specific)	 IREP (NP-801)
Instrument Detected Fault in RPS	0.005	Included in T_1; see Table 2.4
Scram Due to Plant Occurrences	0.536	Included in T_1; see Table 2.4
Spurious Trip Due to RPS Instrumentation	1.298	Included in T_1; see Table 2.4
Manual Scram (No Out-of-Tolerance N.S.S.S. Condition)	0.119	Included in T_1; see Table 2.4
Total	1.958	

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in Categories 1 and 3. The total frequency of these initiators is 4.46 in the ISAP study and 5.56 in the IREP study. Thus, the ISAP initiators frequency for these categories is about 20 percent lower than the IREP frequency in these categories. The total frequency of initiators in this category considered in the IREP study and not considered by the ISAP in any category is 1.00 which is another 20 percent of the total ISAP frequency. Overall, the total frequency of the Categories 1 and 3 which have common mitigating systems requirements is 4.58 in the ISAP study and 6.6 in the IREP study. Thus, the total ISAP initiators frequency for these categories is about 30 percent lower than the IREP initiators frequency.

The ISAP Category 2 transients are reactor transients with the power conversion system unavailable. The frequencies of these intitiators are shown in Table 2.6. In this category, the IREP study included two initiators caused by support system failures. These initiators were treated separately by the ISAP study and are discussed in Section 2.4. Excluding these events, the total frequency for this category is 0.435 for the ISAP study and 2.02 for the IREP study. Thus, the ISAP initiators frequency is about 80 percent lower in this case.

The ISAP Category 4 transients are the "loss of feedwater transients" which in the IREP study include two support system initiators and are shown in Table 2.7. Excluding these two events, the loss of feedwater system initiator in the ISAP study is about 60 percent higher than the value in the IREP study.

The fifth ISAP transient category is the "loss of normal power transient" shown in Table 2.8. In this category, the ISAP frequency is about 40 percent lower than the IREP frequency.

Finally, as was mentioned earlier, the inadvertent opening of safety/relief valves was treated in the ISAP study as an LOCA initiator. This event was considered as a transient initiator in the IREP study. The frequency of this event is 2.02×10^{-2} in the ISAP study and 0.2 in the IREP study. The primary reason for this difference is replacement of the old safety/relief valves with a newer, more reliable set of valves.

Table 2.6 Comparison Between ISAP and IREP Initiator Frequencies Included in the "Reactor Transient With Power Conversion System Unavailable" - Category 2

Initiator	Frequencies (Per year) ISAP (Plant-Specific)	 IREP (NP-801)
Load Rejection with Turbine Bypass Failure	0.002	
Turbine Trip with Turbine Bypass Failure	0.002	
Total Closure of One or More MSIVs	0.405	0.75
Loss of Normal Condenser Vacuum	0.026	0.67
Feedwater Increasing Flow	Included in Category 1; see Table 2.4	0.31
Pressure Regulator Fails Open	Included in Category 1; see Table 2.4	0.29
Loss of Circulating Water System*		0.06**
Loss of Plant Air Compressors*		0.06**

* Initiators based on support system failure
** Plant-specific data

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Table 2.7 Comparison Between ISAP and IREP Initiator Frequencies Included in the "Loss of Feedwater Transients" - Category 4

Initiator	Frequencies (Per year) ISAP (Plant-Specific)	 IREP (NP-801)
Loss of Feedwater	0.096	0.06
Loss of Turbine Building Closed Cooling Water System*		0.06
Loss of Service Water System*		0.06
Total	0.096	0.18

*Initiators based on support system failure

Table 2.8 Comparison Between ISAP and IREP Initiator Frequencies Included in the "Loss of Normal AC Power Transient" - Category 5

Initiator	Frequencies (Per year) ISAP (Plant-Specific)	 IREP (NP-801)
Loss of Offsite Power	0.124	0.16
Loss of Auxiliary Power		0.04
Total	0.124	0[illegible]

2.1.4 Support System Transients

To identify the plant-specific transient initiators due to support system failures, the ISAP study performed system level failure mode and effect analyses on the following classes of systems:

1. Cooling Water Systems
2. Electrical Systems
3. Power Conversion Systems
4. Auxiliary Systems.

As a result of these analyses, four plant-specific initiators were identified. The frequencies of initiation of these events were calculated by a detailed analysis of the support system responsible for their initiation. These frequencies and the corresponding values used in the IREP study are shown in Table 2.9. The IREP initiator frequencies shown in this table are calculated using a zero failure approximation, i.e., the values shown are conservative bounding estimates. Overall, for the support system initiators analyzed in both studies, the ISAP frequencies are from one to two orders of magnitude smaller than the IREP frequencies based on a more detailed support system analysis. The only exception is the service water system where change in its success criteria in the ISAP study has resulted in an increase in the short-term loss of service water system initiating frequency.

In the next section, a discussion on the event-tree analysis used in the ISAP and IREP studies will be presented.

2.2 Event Tree Analysis

The event tree analysis performed in the ISAP study has a number of differences from that performed in the IREP study. Some of the differences are conceptual and apply in general to all of the event trees, while others

Table 2.9 Comparison Between ISAP and IREP Support System Initiator Frequencies

Initiator	Frequency (Per year) ISAP	IREP	Comments
Total Loss of Service Water (With Recovery)	7.83E-3	6.0E-4*	Included in T_3 in IREP, see Table 2.7
Loss of T.B.S.C.C.W.	8.05E-4	0.06	Included in T_3 in IREP, see Table 2.7
Loss of R.B.C.C.W.	4.73E-4	-	
Loss of 120 V Vital AC Power	1.65E-2	-	
Loss of Circulating Water System	-	0.06	Considered part of transients with loss of PCS in ISAP
Loss of Plant Air Compressors	-	0.06	Considered bounded by other transients in ISAP

* This number consists of an initiating frequency of 0.06 and a recovery factor of 1.0×10^{-2}.

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are more specific to a particular tree. The conceptual differences will be discussed here, and the specific differences will be discussed in subsequent sections.

The first difference is that the ISAP study included cognitive operator errors directly on the event trees. These are errors in the decision-making process during an accident. The IREP study did not individually assess these cognitive errors, but rather included them in the assessment of procedural errors. From the standpoint of event tree analysis, this difference in methodology does not significantly affect the final results. When properly evaluated, it makes no difference whether these errors are included independently on the tree or are incorporated at the system level. However, the method of analysis utilized for the human reliability analysis in the ISAP study is significantly different from that used in the IREP study in that cognitive errors were not included in the IREP study. This is not an issue of event tree modeling, but rather that ofhuman reliability and is discussed in more detail in Section 5.0 on human reliability analysis.

The ISAP study also included recovery actions (such as restoration of offsite power) as events on the event trees. In the IREP study, these actions were evaluated separately and incorporated into the analysis at the sequence cut set level. This difference does not significantly affect the results of the analysis, since (as above) either method adequately incorporates the actions evaluated.

The ISAP study did not make a distinction between short-term core melts with and without containment cooling. That is, no credit was given for the operation of the containment cooling system to delay containment failure given that a core melt was occurring in the early or intermediate time frames. This distinction was made in the IREP study. This does not affect the results of the ISAP study in terms of the core melt frequency and timing, since the containment cooling system cannot prevent a core melt in these scenarios. The only possible effect is in the area of plant damage states and consequences. This is an insignificant difference between the two studies because the IREP study determined that all of these sequences would have the same consequences whether or not containment cooling was successful (i.e., the release category split fractions were the same in both cases).

The following sections discuss specific differences in the event trees in the ISAP study and those representing the equivalent initiators in the IREP study. However, before beginning those discussions, it is useful to make a general observation regarding the ISAP study event trees versus the IREP study event trees. Despite the differences in appearance between the two sets of trees, the phenomenologies represented are essentially identical. That is, the functional and systemic failures leading to core melt are nearly the same in both studies. This becomes obvious when one attempts to identify equivalent sequences from both studies. It is generally possible to select any sequence from the ISAP study and identify an equivalent sequence (or sequences) which were analyzed in the IREP study, although the details of the quantification may be different. This exercise is performed in Section 3.0 for the dominant ISAP sequences and is discussed in some detail in that section. The one major exception to this is the Anticipated Transients Without SCRAM (ATWS), which are quantified significantly differently in the two studies. This is discussed in detail in Section 2.2.4.

2.2.1 Reactor Transients Event Tree

The ISAP study event tree includes a cognitive error of the operator failing to decide to restore RPV level when the feedwater system fails to continue to operate after the trip. This error encompasses the entire decision process of attempting to restore feedwater, initiating the isolation condenser, or depressurizing the RCS and using low pressure safety pumps, thus creating a linkage between the actions. The IREP study evaluated each of these alternatives to provide cooling; however, they were considered separate actions. This is a significant difference between the two studies which can result in substantial differences in human error and recovery actions, as will be discussed in Section 2.4. This difference in methodology is due in part to Millstone's change to symptom-oriented procedures and in part to advances in the methods available to analyze cognitive errors which have been developed since the IREP study. This is discussed in more detail in Section 2.4.

The ISAP study event tree also includes an event for restoration of AC power. This is included for the purpose of evaluating support states involving a consequential loss of power following a non-LNP event. As

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discussed in Section 2.2.4, this was not analyzed in the IREP and has a measurable effect on the results.

2.2.1.1 Loss of Feedwater Event Tree

The comments on the reactor transient event tree apply to this event tree as well. The cognitive error modeled in the los of feedwater event tree applies only to those sequences where either the isolation condenser fails or a safety/relief valve sticks open, thus requiring the operator to decide to restore the RPV level.

2.2.1.2 Loss of Normal Power (LNP) Event Tree

The ISAP study event tree considers a cognitive error of failing to decide to restore reactor pressure vessel level, which is similar to the failure to manually depressurize the reactor coolant system (RCS) evaluated in the IREP study. The difference is that in the ISAP study, this error is considered to occur prior to reaching automatic safety actuation conditions, and it includes the decisions to manually start the isolation condenser and to attempt to restore offsite power, even though the Isolation Condenser (IC) will eventually start automatically and the operator has additional time to actually recover offsite power. This particular handling of this cognitive error, while different from the IREP, yields a logically identical model and thus does not affect the results.

The ISAP event tree includes an event for cross-connecting the 4.16kv safety busses so that one of the emergency power supplies can pick up some loads from the opposite train. This action only affects the availability of shutdown cooling, and only in a minor way. It does not have any significant effect on the results.

The ISAP study event tree also includes an event for the recovery of offsite power, which was adequately considered in the IREP study at the sequence cut set level. However, a notable difference is that the IREP study assumed that recovery of offsite power terminated the sequence successfully. The ISAP study, however, models the other actions necessary to initiate the systems required to actually terminate the sequence following the recovery of offsite power. This is a more detailed and accurate method than the IREP assumption, which was based on the belief that these scenarios were unlikely once power was restored. This difference does have an effect on the results.

The ISAP study event tree has an event which represents the actuation signal required for the plant to automatically respond to the loss of normal power event. This was handled in the fault tree models in the IREP study, rather than at the event tree level. Both methods are adequate if properly applied, which is the case.

2.2.1.3 Station Blackout

This tree is just a specific version of the LNP tree to cover the case where all AC power is unavailable. Thus, the comments discussed above for the LNP apply similarly to this tree, with two minor modifications.

First, the cognitive decision process includes the additional decision to conserve DC battery power by stripping nonessential DC loads. This was not considered in the IREP study, but did not effect the results.

Second, the tree considers sequences where the core is damaged but does not melt. This occurs in time frames where the power is not restored in time to prevent the core from briefly becoming uncovered but power is restored prior to significant uncovery. The IREP study did not make this distinction, but it is not important unless one is interested in the possibility of minor core damage. The time frames used for preventing core melt are similar to those used in the IREP study, whereas the time frames used for preventing damage are somewhat shorter. Thus, there is no effect on the core melt sequences.

2.2.2 Support System Initiator Event Trees

These ISAP event trees are subsets of the transient and loss of feedwater event trees. They are designed specifically to take into account the changes in system capabilities due to these initiators. The differences discussed for the transient and LOF event trees therefore generally apply to these trees. Otherwise, there is nothing notable about these trees and, in fact, it would have been equally reasonable to utilize the transient and LOF trees to evaluate these initiators.

2.2.3 Loss of Coolant Accident (LOCA) Event Trees

The LOCA event trees in the ISAP and IREP studies are fairly similar except for the new ISAP event tree for the small-small break LOCA which is discussed in the next section.

2.2.3.1 Small-Small Break Event Trees

This ISAP event tree, which is used for the lower end of the IREP small break size, has a number of differences from the IREP small break event tree. The first difference is that automatic pressure relief does not appear on the tree. In the ISAP study it was concluded that these breaks are too small to result in high drywell pressure; therefore operator action to manually depressurize the reactor is required. This seems to be a reasonable conclusion missed in the IREP study because the IREP study only considered break size ranges analyzed in the FSAR, which did not separately consider the small-small break size. Intuitively, however, it seems reasonable that there should exist breaks which are small enough that high drywell pressure would not occur. This difference had an effect on the results of the analysis.

Another difference is that in the ISAP study it was concluded that feedwater system could not continue to run indefinitely without some operator intervention. The operator is required to start a high-capacity condensate transfer pump to replenish the hotwell to provide sufficient suction water for the feedwater system. This is required to replace water lost through the break. In the IREP study it was assumed that sufficient water would be supplied automatically by the condensate transfer system (CTS); however, only a small capacity CTS pump will start automatically to replenish the hotwell. Thus, an additional branch appears on the tree for the required action of manually starting a higher capacity pump. This difference had an effect on the results.

A third difference is the consideration of a cognitive error by the operator of failing to realize the need to recover RPV level when the feedwater system has failed. This includes the same actions as the one discussed for the transient trees, and links together all possible actions to recover level. As mentioned before, this has a significant effect on the results.

The ISAP study also considered a cognitive error of commission, that of the operator misdiagnosing plant conditions and prematurely terminating ECCS flow. This type of error was not considered in the IREP study, and it has an effect on the results. It is discussed in greater detail in Section 2.4 on human reliability analysis.

Finally, the ISAP study event tree has branches for successful long-term cooling using the main condenser or shutdown cooling (SDC) systems. In the IREP study no credit for these cooling methods was allowed because they normally require that the vessel be isolated so that no coolant is lost. However, it is conceivable that these methods may work for the very small breaks which comprise this break range. This is especially true when using the SDC system, where the SDC system can cool water taken from the vessel and return it to the vessel while the vessel level is being maintained by circulating torus water through the core spray or LPCI systems to make up for continued coolant loss through the break. All that would be required is that adequate mixing take place in the vessel, which is a reasonable assumption. The use of the main condenser is based on the fact that the condenser is under vacuum conditions, while the torus is at about atmospheric pressure. Hence, it is logical to assume that after a period of time all steam would be dumped to the condenser since this should be the path of least resistance. Further, slight coolant losses can be replaced by the normal condensate transfer system. Thus, both of these cooling modes appear to be reasonable.

2.2.3.2 Small and Large Break Event Tree

There are two major differences between the ISAP study event trees for these initiators and the analogous IREP study event trees. First, both ISAP study event trees contain the cognitive error of commission (premature termination of ECCS flow) mentioned in the previous section. For these initiators this difference does not have any significant effect on the results.

The second difference is that the feedwater system is not considered to be a sufficient mitigating system in the ISAP study for these breaks. This is based on the inability, even with manual action, of the condensate transfer system (CTS) to provide sufficient makeup flow to the condenser hotwell for breaks of these sizes. Thus, feedwater is assumed to be lost in a relatively short time. The IREP study assumed that CTS flow was sufficient, except for large liquid breaks, based on the Millstone FSAR. Regardless, this difference did not have a significant effect on the results, and further investigation is therefore not warranted.

2.2.4 ATWS Event Tree

There are significant differences in the way each of the two studies evaluates ATWS events. The IREP study assumed that an ATWS always resulted in a core melt, except for transients where the power conversion system (PCS) was available and continued to operate. Much study has been done on ATWS since that time, by both the NRC and the nuclear industry, and a much greater understanding of ATWS events has been attained. This understanding has allowed for the modification of plant design and development of new procedures to mitigate ATWS events. The present NRC position on ATWS is contained in the recently developed ATWS rule (10CFR50.62). It is more fruitful to compare the ISAP study evaluation with the analysis in the rule as opposed to that from the IREP study, since the former represents more advanced thinking on ATWS.

The ISAP study considers two general cases of ATWS: Power Conversion System (PCS) available and PCS unavailable. This is consistent with the ATWS rule. Each case will be considered separately.

For the PCS available case, the ISAP study deviates from the rule in that it assumes that operator actions are not as complex or imperative as the rule states. It takes substantial credit for the ability of the PCS to automatically maintain adequate heat removal for an extended period once the recirculation pumps are tripped. This is reasonable for the Millstone 1 plant. The need for complex operator actions in a short time frame in the ATWS rule is based on certain assumptions in the rule, as follows:

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> "It has been estimated that power will equilibriate at around 20 to 40 percent of full power.... A BWR is typically designed to bypass up to 25 percent of steam flow to the condenser. Thus, if the ATWS transient has not involved MSIV isolation or loss of condenser, a maximum of 15 percent of steam flow will be directed to the suppression pool."

It is this loss of steam to the suppression pool which is the limiting condition for the operator actions in the ATWS rule. However, Millstone 1 is not a typical BWR. Its bypass capability is 100% of steam flow; thus, there would be no loss of steam to the suppression pool. For this reason, we conclude that the ISAP event tree for an ATWS with PCS available is acceptable despite its deviation from the ATWS rule.

The only other comment we have on this case is that for the sequences where core melt does not occur, core damage is assumed. For this type of sequence, where the condenser is available at least until the reactor is shut down using the SLCS, no undue stress on the core would be expected. The shutdown process would appear to be normal, and no core damage resulting in cladding failures and radioactive releases would occur. Thus the end state for these sequences should be success, not damage.

For the PCS unavailable case, the ISAP study and the ATWS rule are in general agreement on the basis behind the mitigation of an ATWS. That is, they both consider the limiting conditions for success to be injecting boron to shut down the reaction and maintaining sufficient heat capacity in the torus (not exceeding the torus heat capacity temperature limit for the prevailing RCS pressure). Also, the operator actions in the ISAP study are the same as those described in the rule. They deviate in the capability of the standby liquid control system (SLCS) to mitigate the ATWS and in the absolute limit of 200° torus temperature. Specifically, the ATWS rule states the following:

> "For these cases where all of the reactor power is dissipated in the suppression pool, the suppression pool temperature would exceed 200° F slightly even if the operator immediately followed the procedures and actuated the [43 gpm] SLCS. If SLCS capability is increased to 86 gpm, the operator must act within two minutes after the transient begins in order not to exceed the 200° F suppression pool limit. Therefore, it

was conservatively assumed that all isolation transients will exceed the 200° F containment suppression pool limit with the current SLCS capacity of 43 gpm."

Thus, an event tree for Millstone 1 based on the ATWS rule would not have a success branch for SLCS because it is assumed to have insufficient capacity. However, it is important to note two things. First, the rule used the word "conservatively" to describe its assumption. Further, the analysis is apparently based on a "typical BWR." Once again, Millstone 1 is not typical. Its suppression pool is the same size as typical BWR-4s, but its core power is only about 60% of a typical BWR-4. Thus, Millstone 1 has a greater heat rejection capability (in terms of equivalent full power seconds before exceeding 200° F). Further, the heat capacity temperature limit curve for Millstone does allow the torus temperature to exceed 200° F if the RCS pressure is sufficiently low, although we cannot verify the acceptability of this curve. Therefore, it may be possible that a 43 gpm SLCS is sufficient for Millstone 1. For the present, however, we must reserve judgment until we can review thermal/hydraulic calculations of this sequence to determine if this is so and how long the operator has to initiate SLCS. If a 43 gpm SLCS is not sufficient, ATWS will become a more significant contribution to core melt, assuming all other conditions remain the same (which they do not; see RPS analysis comments in Section 2.3.2, operator response comments in Section 2.4.2, and ATWS summary in Section 3.3). A detailed reanalysis of ATWS, which evaluates the significance of these differences, is given in Section 3.3.

2.2.5 Inclusion of Support Systems in Event Tree Quantifications

The ISAP study used an entirely different method from the IREP study to consider the effect of support systems on the sequences. In the IREP study the support system fault trees were merged with the front line system fault trees to create complete fault trees for the front line systems which include all potential support system faults. In the ISAP study, the support systems were evaluated separately and a support system event tree was used to define support states. These support states define the possible combinations of support system success and failures which can exist following an initiating event. Thus, each event tree is actually evaluated

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a number of times (once for each support state), and the system failure probabilities used are conditional on the support state being evaluated.

The review of the ISAP support states and the front line systems showed that the system interfaces modeled in the IREP study, as modified by actual plant changes, are adequately represented in the ISAP analysis.

The significant difference between the two support system interface models is that the ISAP study considered the subsequent loss of AC power after a non-LNP initiating event. The IREP study did not consider this possibility. The support states that result from this subsequent loss of power on either emergency bus do contribute to three of the ISAP study dominant accident sequences, all reactor transient initiated sequences. Two of these sequences would not have been dominant sequences if the subsequent loss of power support states had not been considered. The total contribution of these two sequences is approximately 5% of the total core melt frequency calculated in the ISAP study.

2.3 Component and Plant Systems Reliability Analysis

This section provides a brief review of both the component failure data used and the system reliability analysis performed in the Millstone 1 ISAP study. The review of the component unavailability data consists of a comparison of the data used in the ISAP study with that used in the IREP study. No other attempt has been made to verify the accuracy of the plant-specific data used in the ISAP study. The review of the system reliability analysis was also primarily a comparison of the ISAP study system models to those used in the IREP study. This comparison was limited to a comparison of the success criteria, support system interfaces, and system descriptions in the two studies. A detailed review of the system fault trees used in the ISAP study was not performed. However, the system unavailabilities used in the ISAP study were assessed for their reasonableness based on information that could be extracted from the IREP study.

2.3.1 Component Failure Data

The ISAP study applies Bayes Theorem to a combination of generic data and plant-specific data to develop the failure rate data used in the study.

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WASH-1400 was selected as the generic data source. The demand failure data in WASH-1400 were assigned a Beta distribution to generate prior means and variances; a Gamma distribution was assigned to the hourly failure data. The means and variances were then modified using the plant-specific data by applying Bayes Theorem.

The IREP study used WASH-1400 data almost exclusively. The only failure data not taken from WASH-1400 were for components not specifically identified in WASH-1400 or components where plant data justified using a plant-specific failure probability instead of the generic data. (All of the components found to be significant contributors to the IREP study dominant accident sequences were modeled using generic WASH-1400 data.)

Table 2.10 lists the failure data used in the two studies for significant components, i.e. those components whose failures are important contributors to the core melt sequences.

For most components, the differences between the data used in the two studies are not significant. There are only three component failures where the differences in the data significantly impacted the quantification of the dominant accident sequences. The failure probability used for AC breakers is significantly lower in the ISAP study than in the IREP study, particularly for 4160V breakers. The ISAP study also used a significantly smaller failure probability for the diesel generator failure (both failure to start and failure to run) and for the gas turbine generator failure to run once started. All of these reduced failure probabilities would reduce the impact of loss of normal power (LNP) accident sequences. These failure probability reductions are a significant reason that the LNP sequences are not as dominant in the ISAP study as they are in the IREP study.

The differences in the remaining component failure probabilities are either insignificant or affect components that do contribute significantly to dominate accident sequences.

Table 2.10 COMPARISON OF IREP AND ISAP COMPONENT FAILURE DATA

COMPONENT	FAILURE ON DEMAND[+] (MEAN)	
	ISAP	IREP[*]
MOV (Outside Drywell)		
Fail to open	4.45E-3	1E-3
Fail to close	3.00E-3	1E-3
MOV (Inside Drywell)		
Fail to open	3.79E-3	1E-3
Fail to close	4.90E-3	1E-3
ECCS check valves		
Fail to open	1.15E-4	1E-4
Fail to close	6.60E-4	--[**]
Feedpump check valves		
Fail to close	2.29E-3	--[**]
All electric motor-driven pumps		
Fails to start	-	1E-3
Fails to run	-	9E-5/hr
ECCS Pumps		
Fail to start	7.48E-4	
Fail to run	7.99E-5/hr	
Service Water Pumps		
Fail to start	7.89E-4	
Fail to run	3.81E-5/hr	
Emergency Service Water Pumps		
Fail to start	6.41E-3	
Fail to run	7.99E-5/hr	

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[*] Ref. "IREP-Analysis of the Millstone Point Unit 1, NPP" Vol. 1; Table 7.1 a,b. Data given were based on monthly testing, except where noted IREP used median values, data has been converted to mean values.

[**] Not modeled in the IREP Study.

[+] For components tested only during refueling outages, both studies modified component failure data (for valves and breakers) to account for the impact of the extended test interval.

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Table 2.10 COMPARISON OF IREP AND ISAP COMPONENT FAILURE DATA
(Continued)

COMPONENT	FAILURE ON DEMAND (MEAN)	
	ISAP	IREP*
R.B.C.C.W. Pumps		
Fail to start	9.24E-4	
Fail to run	9.71E-6/hr	
Shutdown Cooling Pumps		
Fail to start	2.84E-3	
Fail to run	9.59E-6/hr	
T.B.S.C.C.W. Pumps		
Fail to start	9.67E-4	
Fail to run	1.02E-5/hr	
Feedwater Pumps		
Fail to start	9.48E-4	
Fail to run	1.46E-6/hr	
Condensate Booster Pumps		
Fail to start	1.66E-3	
Fail to run	5.05E-5/hr	
Condensate Pumps		
Fail to start	1.07E-3	
Fail to run	8.60E-7/hr	
Emergency Condensate Tranfer Pumps		
Fail to start	1.12E-3	
Fail to run	7.99E-5/hr	
C.R.D. Pumps		
Fail to start	1.57E-3	
Fail to run	1.58E-6/hr	

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* Ref. "IREP - Analysis of the Millstone Point Unit 1, NPP" Vol. 1; Table 7.1 a,b. Data given were based on monthly testing, except where noted IREP used median values, data has been converted to mean values.

Table 2.10 COMPARISON OF IREP AND ISAP COMPONENT FAILURE DATA (continued)

COMPONENT	FAILURE ON DEMAND (MEAN) ISAP	IREP*
Diesel-Driven Fire Pumps		
Fail to start	4.77E-2	
Fail to run	7.97E-4/hr	
Motor-Driven Fire Pumps		
Fail to start	1.13E-3	
Fail to run	7.99E-5/hr	
4.16KV Breakers		
Fail to operate	1.34E-4	1E-3
480V Breakers		
Fail to operate	6.14E-4	1E-3
Diesel Generator		
Fail to start	6.71E-3	3E-2
Fail to run	1.12E-3/hr	9E-3
Gas Turbine Generator		
Fail to start	4.80E-2	3E-2***
Fail to run	1.97E-3/hr	9E-3
Battery Charger		
Fails to operate	1.02E-5	--

*** Gas Turbine Generator failure probability was found to be similar to that of Diesel Generator - (Ref. "IREP - Millstone Point Unit 1"; Vol. 1, pg. 7-2.

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2.3.2 Plant Systems Reliability Analysis

The review of the plant systems reliability analysis performed in the ISAP study was limited to a review of major differences found between that study and the IREP study. The system descriptions in the two studies were compared with particular emphasis on system success criteria and the systems dependencies, i.e. support system interfaces.

A detailed analysis of the fault trees was not possible during the time available for the review. However, in some cases changes in the plant design which impacted this part of the analysis were identified. Differences in the identification of systems used in each study are also noted but not necessarily discussed in detail here.

There are two systems where differences in the success criteria used in the ISAP and IREP studies have resulted in significant changes to the calculated system reliabilities. The most important difference is in the success criteria for the Alternate Shutdown Cooling (SDC) System which is the Containment Cooling (CC) mode of operation of the Low Pressure Coolant Injection (LPCI) system (referred to as LPCI/CC in the Millstone 1 IREP study). This system is one of the long-term cooling systems and uses the Emergency Service Water (ESW) system to remove decay heat. The LPCI system is a two-train system with each train consisting of two pumps and a single heat exchanger (used only in the containment cooling mode). The ESW system consists of two trains with each train consisting of two pumps. Each ESW system train supports only one LPCI train, i.e., two ESW pumps provide flow to one LPCI system heat exchanger; the other two provide flow to the second heat exchanger. The success criteria used in the IREP study for these systems were one LPCI pump operating with the corresponding heat exchanger and one of two corresponding ESW pumps operating. The ISAP study success criteria for these two systems are much more stringent. The ISAP study assumes that one LPCI pump in each train is required and both heat exchangers are needed. To remove the decay heat, the ISAP study uses a success criterion that requires all four ESW pumps to operate. This change in the success criterion results in a much higher, by nearly two orders of magnitude, alternate SDC system failure probability in the ISAP study than in the IREP study. It should be noted that no system failure probabilities were provided in the IREP study. The change in system failure probabilities is based on estimated values for the systems in the IREP study. These estimates are derived from the IREP study sequence quantification. The differences in the system success criterion account for nearly all of the two orders of magnitude difference in system failure probability.

The second system for which different success criteria were used in the two studies is the Service Water System (SWS). In the IREP system reliability analysis, the success criteria for the SWS, under all conditions, require one of the four SWS pumps to be operable. In the ISAP study, the SWS success criteria are sequence dependent. For most sequences, two of four SWS pumps are required, but for the Loss of Normal Power (LNP) sequences the SWS success criteria used were either two pumps operable or one pump operable and valve SW-9 must close. (The closure of this valve isolates nonessential cooling loads from the SWS.) This change in system success criteria does not appear to have made a significant difference in the results of these two studies except for the frequency of initiation of a loss of service water transient. The impact on the initiator frequency is discussed in Section 2.1.4.

Some minor differences in the support system interfaces used in the two studies were also found. None of these differences would appear to make a significant difference in the results of the studies.

In the Shutdown Cooling (SDC) system, the ISAP study shows a support system interface where the loss of either DC bus (101A or 101B) would result in the loss of the SDC system. The IREP study model of the system indicated that failure of either DC bus would disable only half of the SDC system. Since the support states where one DC power train is lost do not contribute significantly to the ISAP study results, this difference in support system requirements does not appear to be significant.

The second difference in support system requirements affects the SWS. In the ISAP study, the valve that is required to close on an LNP, SW-9, is modeled as being powered from one of the two main AC power trains. In the IREP study, this valve is modeled as being powered from a bus that could be energized by either of the two AC power trains (a normal supply with an automatic transfer to a backup supply). This difference does not appear to significantly affect the results of either study.

Other than these two differences, the modeling of the support system interactions in the two studies are in agreement with each other. The differences in methodologies, support states versus merged fault trees, has not resulted in differences in the results of the studies. But the different methodologies did result in differences in the way some support systems were modeled. In the IREP study, there was only one AC power fault tree that included vital and instrument AC, and the actuation logic for the ECCS was included in each system fault tree. In the ISAP study, separate support system fault trees were produced for vital AC, instrument AC, and the actuation logic. These differences did not impact the study results.

At least two equipment changes have been made at Millstone 1 since the IREP study that were incorporated into the ISAP study. A change in the LNP reset logic was incorporated that would reduce significantly the impact of logic failures. These logic failures were a significant contributor to the IREP study dominant accident sequences. This modification reduces the importance of LNP initiated sequences in the ISAP study. The second modification was to the makeup valve (ICM-10) to the isolation condenser. The power supply to this valve was changed from AC power to DC power, greatly increasing the reliability of the isolation condenser makeup system, especially during an LNP event. This modification would also reduce the importance of several IREP study LNP sequences.

Finally, the reactor protection system (RPS) was modeled differently in the two studies. The ISAP study used a demand failure probability of approximately 5E-5 based on a Bayesian analysis using historical data as of 1979. This is an old analysis and is probably quite conservative. The IREP study used a value of approximately 1E-5 based on a detailed fault tree analysis of the system. Common cause mechanical failure was dominant, and there was no contribution from electrical failures. The NRC's ATWS rule (10 CFR 50.62) agrees with the IREP study in that a 1E-5 RPS failure probability is a reasonable estimate for the mechanical failure contribution. (This excludes an additional 2E-5 contribution for electrical failure of the RPS for the RPS design existing at the time of the IREP study. If a plant has alternate rod insertion (ARI), the rules state that these electrical contributions are eliminated. Millstone Unit 1 now has ARI.) It would appear that the ISAP study used a conservative estimate for its RPS failure probability. The impact of this and other competing factors on the ATWS frequency is discussed further in Section 3.3.

2.4 Human Reliability Analysis (HRA)

There are significant differences between the HRAs performed in the IREP study and the ISAP study. In particular, two areas are most significant. First, the ISAP study separately considered cognitive errors, which are errors in diagnosing and interpreting plant conditions and deciding (in a conceptual sense) what actions are appropriate. In the IREP study, these types of errors were not explicitly analyzed. At the time of the IREP study, the only useful tool for quantifying human error was the Technique for Human Error Rate Prediction (THERP) (5), a technique which allowed for detailed modeling of procedural-type errors on a step-by-step basis. It considered the concept of decision making errors only as it applied to certain steps within a procedure. Since that time, new understanding of the cognitive errors has been gained, allowing for the quantification of the decision making process from an overall diagnosis of plant conditions outside of the step-by-step procedures. The consideration of cognitive errors in this manner is a major advance in HRA, and is generally recognized by experts as being a vast improvement over THERP. It should be noted that THERP is still recognized as the state of the art for evaluating strictly procedural errors. Two useful tools have been developed for the quantification of cognitive errors: the Time-Reliability Correlation (TRC) model (6), and the Systematic Human Action Reliability Procedure (SHARP) model (7). The ISAP study makes use of both of these modeling techniques. The use of cognitive modeling in this study has a significant effect on the results when compared with the IREP study. We believe the ISAP methodology is more reasonable.

The second significant difference between the two studies is also related to a change which has taken place since the IREP study. Millstone Unit 1 has converted its procedures to the new "symptom oriented procedures." These procedures are more concise, more understandable, and easier to follow than the procedures which existed at the time of the IREP study. Thus, procedural errors are less likely to occur during certain key operator actions. This has a significant effect on the ISAP results. In most cases, in the ISAP study procedural errors were also considered in addition to

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cognitive errors. That is, the probability of failing to properly perform the manipulations required (procedural error) was evaluated given that the operator has properly diagnosed the situation (cognitive success). Generally, these errors are incorporated directly into the system failure rate determinations. A significant exception to this, which is discussed in more detail later, is in the ATWS analysis. For some reason, procedural error was not fully considered despite the rapid and complex nature of the actions required.

Even with these differences, the HRA in the ISAP study is quite unsophisticated and for the most part "screening values" are used. The analysis performed was very simplified, and the analysts did not take full advantage of the available modeling tools. Further, there was virtually no detailed documentation of the errors analyzed, either in the summary report or in the QA calculation files at the utility's headquarters. This made the review of the HRA extremely difficult and, even after discussions with the analysts, several areas were left where the details of the analysis could not be verified. To a large extent it was only possible to review the results of the HRA by comparing them to alternative screening techniques.

2.4.1 Cognitive Error Modeling

The ISAP study explicitly models cognitive errors of decision-making. This was not done in the IREP study. These errors represent incorrect decisions by the operator based on his misunderstanding plant conditions. This results in the operator failing to enter the appropriate emergency operating procedure (EOP). In the IREP study, the only operator errors leading to a misunderstanding consisted of whether the operator correctly read the instrumentation. That is, if he correctly read the meter/annunciators, it was assumed that he entered the correct procedure. Cognitive error modeling accounts for the addition of the possible error that the operator could fail to correctly interpret the instrumentation even if read correctly. Additionally, the cognitive error concept tends to link together actions which were formerly thought to be relatively independent; i.e., the concept considers that if the operator fails to understand the plant conditions he may take no actions whatever. In the case of the ISAP study, this is particularly important because of the format of the new Millstone 1 procedures. The procedures in force at the time of the IREP study could be very complex and confusing; however, they had a certain amount of independence in that the operator might take an action to restore a system, even if he thought he didn't need to, just because it was unavailable. The new, symptom oriented procedures are much easier to comprehend and follow, but they are very restrictive about what the operator should do for a particular plant symptomatic condition. Thus, if the operator fails to correctly interpret the plant condition, he would undertake a series of tasks or a course of nonaction which would fail to aid his situation. In all, the addition of explicit cognitive error modeling and the switch to symptom oriented procedures is a significant reason for differences between the IREP and ISAP PRA results.

As mentioned previously, the ISAP study utilized two cognitive modeling techniques for quantifying human reliability: SHARP (7) and TRC (6). The next two sections discuss these techniques and the cognitive errors modeled by each.

2.4.1.1 Time-Reliability Correlation (TRC) Model

A TRC model is used to determine the probability of the operator failing to make a correct decision based on the amount of time the operator has available. The basic premise of the model is that the driving factor in the decision process is how long the operator has to think about it. Further, this factor is generally independent of other factors and constitutes a reasonable basis for selecting a screening human error probability (HEP). In order for an analyst to determine the HEP for a particular decision, he need only determine how long the operator has to take action and select the corresponding probability from a time vs. HEP curve. Such curves have been developed by human reliability experts and are published in a number of reports. The ISAP study used a curve from NUREG/CR-3010 (6, Figure 5-2) for quantification.

The ISAP study used the TRC for evaluating cognitive errors where the amount of time for making the decision exceeded about ten minutes. Five errors were evaluated in this way. These errors are shown in Table 2.11. For those actions which were related to scenarios considered in the IREP study, the times used in the two studies are in general agreement. For the actions of initiating emergency condensate transfer and conserving batteries

Table 2.11
Human Errors Evaluated Using the Time Reliability Correlation

Error Description	Time Avail	ISAP HEP	NUREG/CR-2815 HEP
Operator fails to decide to restore IC makeup (IC operating)	50 min.	4.5E-4	2E-3
Operator fails to recognize the need to initiate emergency condensate transfer during small-small LOCA w/FW available	40 min.	7.0E-4	3E-3
Operator fails to recognize the need to manually depressurize during a small LOCA (manual backup to auto actuation)	10 min. (FW operating)	1.5E-2	0.5
Operator fails to recognize the need to conserve DC batteries by shedding non-essential loads during blackout	50 min.	4.5E-4	2E-3
Operator fails to recognize the need to restore RPV level during stuck-open S/RV event	20 min.	3.5E-3	0.1

(not considered in the IREP study) the basis for the time frames appear reasonable. It is worth noting, however, that the HEP values used, although taken from an NRC report, do not correspond with the preferred screening values from NUREG/CR-2815, the PSA Procedures Guide (8). The right hand column of Table 2.11 gives the values which would be obtained if the TRC curve from that report is used. These values are significantly higher and could affect the results of the analysis.

After careful consideration, we have determined that the NUREG/CR-3010 curve used in ISAP is inappropriate for the type of analysis performed. The screening curve from NUREG/CR-2815 should have been used. There are two major reasons for this.

First, the NUREG/CR-3010 curve was developed by a single team of analysts from one organization. Although it is singled out in the report and used in the examples, it is actually only one of several curves discussed in the report. The NUREG/CR-2815 curve, on the other hand, is a consensus curve based on multiple information sources and represents the consensus of a multi-organizational group of experts.

Second, it is apparent from the discussion in NUREG/CR-3010 that the curve selected for use in the ISAP study is not intended for use in a screening analysis. Rather, the use of this curve assumes a detailed human reliability analysis, specifically, the development of an operator action tree (OAT) to represent overall operator response. Additionally, when using this curve it is necessary to specifically evaluate the "thinking time" interval based on the following equation:

$$t_T = t_0 - t_I - t_a$$

where

t_T = Thinking time

t_0 = Overall time from the initiation of an accident sequence to the point by which actions must be completed.

t_I = The time after initiation at which appropriate indications or other clues are given.

t_a = The time it takes to implement the actions decided upon.

This must be done because this curve represents the HEP as a function of thinking time alone. A further consideration when using this curve is the inclusion of modifications to the HEP due to other effects, such as reluctance factors. Additionally, this curve only represents a part of a more detailed HRA of any given human action. It can be used to quantify cognitive decision points on an OAT, but should not be assumed to represent the entire action. The ISAP study did not perform these detailed analyses, which should accompany the use of this curve.

On the other hand, the NUREG/CR-2815 curve was specifically intended as a screening curve. Thus, none of the above considerations are necessary when values are used from this curve. This curve takes into account, as much as possible, all the facets of a human action in the determinations of a reliability number. This is obviously not as accurate as a detailed model. For example, for all actions required within a given time t_0 it implies (by its very structure) that the times t_I, t_a, and t_T are identical for all such actions, as are any procedural error rates associated with them. However, in the absence of a detailed HRA, which is the only way these values can be determined, this curve is expected to give a more reasonable estimate of the HEP for a particular action than the other curve (which applies only to t_T). Therefore, this curve is much more appropriate for the simplified analysis performed in the ISAP study. It should be noted, however, that the state-of-the-art in TRC has progressed past the use of a single curve. Different curves for various behavioral types and action conditions should be used. But this would require a more detailed HRA than was performed by the ISAP study analysts.

As mentioned above and shown in Table 2.11, the values obtained using NUREG/CR-2815 are significantly higher than those used in the ISAP study. The use of these higher values would affect the ISAP results in two cases. These cases are the second and last human errors shown on Table 2.11. The use of an HEP of 3E-3 for the second error (instead of 7E-4) would result in a new dominant sequence, described as follows:

- o Small-small LOCA
- o Feedwater continues operating post-trip
- o Operator fails to initiate emergency condensate transfer
- o Feedwater trips on low hotwell level

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The frequency of this sequence would be 3E-5 and it would fall into plant damage state SE1. This would increase the frequency of this plant damage state by a factor of 2 to 3 and would increase the frequency of small-small break core melt by up to a factor of 2. Overall, the total plant core melt frequency would increase by less than 5%.

The use of an HEP of 0.1 for the last error (instead of 3.5E-3) would also create a new dominant sequence, described as follows:

- Inadvertent opening of an S/RV
- FW fails post trip
- Operator fails to recognize the need to restore RPV level

The frequency of this sequence would be 2E-5 and it would fall into plant damage state TE1. This would increase the frequency of this plant damage state by less than 10% and would increase the frequency of core melt due to inadvertent opening of an S/RV by a factor of less than 2. Overall, the total core melt frequency would increase by less than 5%.

2.4.1.2 Systematic Human Action Reliability Procedure (SHARP)

The SHARP method of cognitive error quantification differs from the TRC method in the selection of the driving factor behind human performance. Whereas the TRC method considers the time available as the driving factor, the SHARP method considers the type of action and the expected behavior. The screening process used in ISAP calls for generating human error probabilities based on the type of action and the expected behavior.

In this model, three human behavior categories are defined. These are: skill-based, rule-based and knowledge-based behavior. The classification of each human action in the ISAP study into one of these categories is based on the following definitions:

- The behavior can be classed as skill-based if the operator is well trained, is motivated to perform the task, and has experience in performing the task.

- The behavior can be classed as rule-based if the operator has a clearly understood set of rules to follow in responding to a well-understood transient or situation.

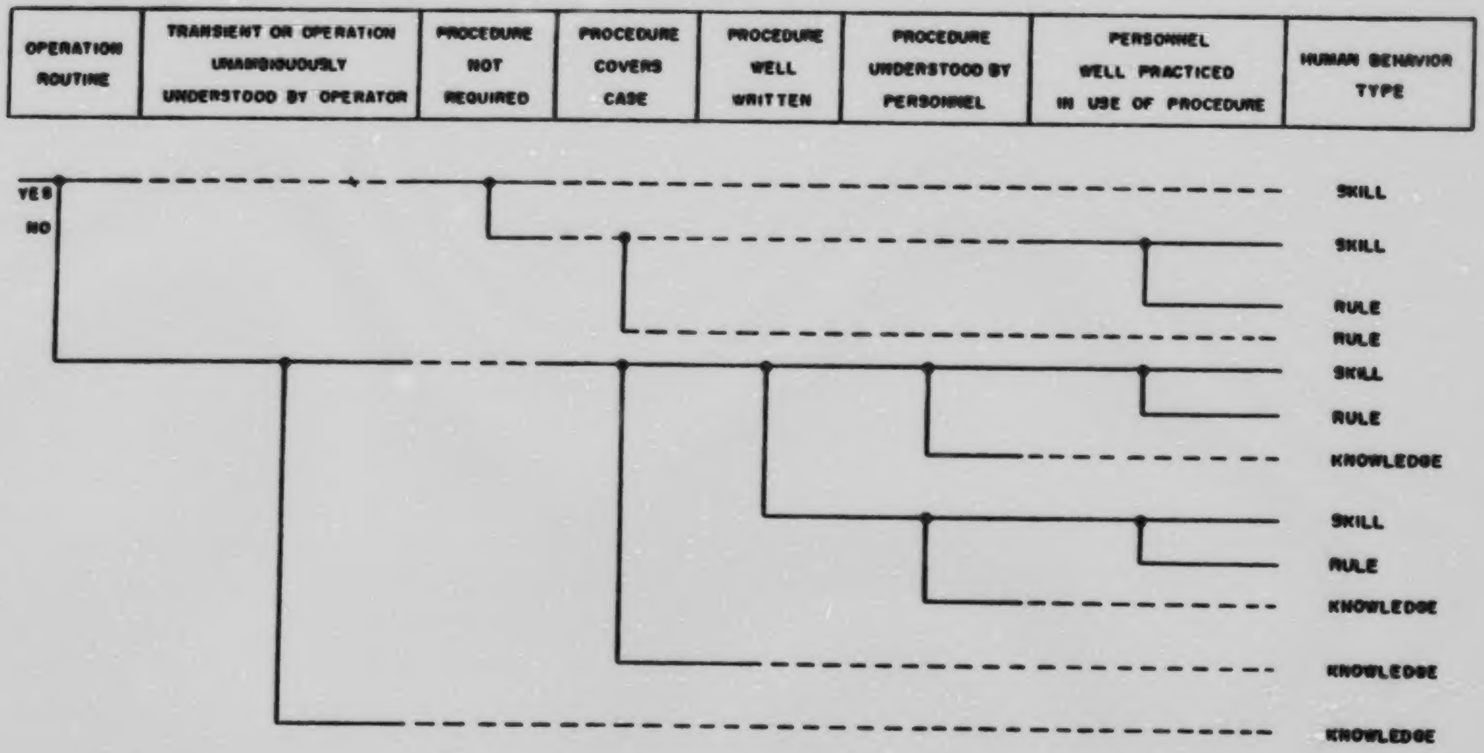
- The behavior can be classed as knowledge-based if the above do not apply or the operator must understand the condition of the plant, interpret some of the instrument readings, or make a difficult diagnosis.

Figure 2.1 is a reproduction of Figure 4.2-3 of the ISAP PSS. This figure shows the logic that was used by each analyst in the classification of different human actions into one of the above categories. This guideline was used so that the classification done by different analysts would be performed in a consistent manner. It should be noted, however, that a certain amount of "analyst creativity" is required in using this logic tree. For example, a nonroutine operation which is covered by a well written, understandable procedure might still be classified as knowledge-based if the amount of time available is short. In this case, the operator may not have time to access the procedure, which would make the operation equivalent to one which lacked a procedure.

Following the classification of each human action, the human error probabilities were found using the values reported in Appendix A of the SHARP report (7). To obtain a screening value for a behavior type from the range of values given in Reference 7, a log-normal distribution was assumed for each range of values. The mean and variance for the human error probabilities in each of these categories used in the ISAP study are shown below:

Behavior Type	Mean	Variance
Skill-based	1.3E-3	1.08E-5
Rule-based	1.3E-2	1.08E-3
Knowledge-based	1.3E-1	1.08E-1

It should be noted that the ISAP study application of SHARP was very simplified. SHARP is intended to be a tool for developing a detailed model of human response, which could include such things as operator action event trees (OAET), THERP trees, and time reliability correlations (TRC).


OPERATION ROUTINE
TRANSIENT OR OPERATION UNAMBIGUOUSLY UNDERSTOOD BY OPERATOR
PROCEDURE NOT REQUIRED
PROCEDURE COVERS CASE
PROCEDURE WELL WRITTEN
PROCEDURE UNDERSTOOD BY PERSONNEL
PERSONNEL WELL PRACTICED IN USE OF PROCEDURE
HUMAN BEHAVIOR TYPE
YES
NO
SKILL
SKILL
RULE
RULE
SKILL
RULE
KNOWLEDGE
SKILL
RULE
KNOWLEDGE
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KNOWLEDGE

Figure 2.1 Logic Trees to Aid in Selection of Expected Behavior Type.

Specifically, the values from Appendix A of the SHARP document used in the ISAP study are screening values which can be used for screening within the SHARP process. However, once that screening is done and the errors with potential safety significance have been identified, it is absolutely necessary to continue the process and perform a detailed HRA, following the SHARP process to completion, for those errors. It is not acceptable to use the Appendix A screening values as if they were final values and to thus base risk decisions on the results using these values. A careful reading of the SHARP document makes it amply clear that the Appendix A material is not a substitute for the entire SHARP process, but is rather one way to perform Step 2 Screening. Thus, the HRA analysts did not fully utilize the SHARP methodology, and it is questionable whether the simplified analysis was reasonable as a screening analysis. However, as discussed further in this section, the results obtained are generally comparable to those expected from other screening techniques and expert judgment.

The human errors evaluated using the SHARP methodology are shown on Table 2.12. Each of these errors was evaluated using SHARP because the operator decision time was assessed to be less than about ten minutes. The most important of these errors is the first one shown on the table. This is the error of the operator failing to recognize that the RPV level is decreasing and that he must respond to it. This error is important for two reasons. First, it appears on virtually all of the event trees because level is the key indicator that there is a problem at the plant (this is true of all BWR's). Second, because of the concept of cognitive errors and the new Millstone Unit 1 procedures, if the operator fails to recognize the need to respond and thus does not enter the level control procedure, it is assumed that he will not take any actions to actuate or recover any systems which could be used to prevent core melt. The ISAP study assumed that this decision had to be made within ten minutes (or in some cases even less) because part of the response includes manually initiating the isolation condenser. If the operator does not do this within ten minutes, it will actuate automatically. We believe that it would have been more reasonable to use time frames which reflect the actual times available. By way of comparison with this alternative approach, Table 2.12 shows estimated actual time frames available to the operator for the three sequence scenarios (Cases A-C) in which this error appears. The time frames shown are the times available for action to prevent core uncovery and core melt. They are

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Table 2.12

Human Errors Evaluated Using the Systematic Human Action Reliability Procedure

Error Description	Basis	TSAP HEP	Est. Actual Time Avail.	NUREG/CR-2815 HEP
Operator fails to recognize the need to restore RPV level (transient and small-small LOCA)	Rule	1.3E-2	Sequence Dependent	
			Case A: Stuck Open S/RV	
			Small-Small LOCA	
			Core uncovery-15 min	0.2
			Core melt-25 min	3E-2
			Case B: IC Fails	
			Core uncovery-25 min	3E-2
			Core melt-45 min	3E-3
			Case C: IC Makeup Fails	
			Core uncovery-70 min	1E-3
			Core melt-90 min	9E-4
Operator fails to recognize the need to disregard the indicated level and flood the RPV when drywell temperature reaches RPV saturation temperature (operator throttles or terminates injection based on erroneous high RPV level indication due to reference leg flashing)	small and small-small LOCA Skill	1.3E-3	Initial Error +30 min recovery	<1E-3
	large LOCA Rule	1.3E-2		
Operator fails to recognize the need to reduce core power following ATWS (W/PCS available) before loss of condenser vacuum	Rule	1.3E-2	3 min	N/A
Operator fails to recognize the need to provide for long term decay heat removal (ATWS w/PCS available)	Rule	1.3E-2	60 min	<1E-3

Table 2.12 (con't.)

Error Description	Basis	ISAP HEP	Est. Actual Time Avail.	NUREG/CR-2815 HEP
Operator fails to recognize the need to reduce core power before torus heats up to 110° F (ATWS w/PCS failed)	Knowledge	1.3E-1	3 min	N/A (ATWS Rule = 0.5)
Operator fails to recognize the need to keep RPV pressure below heat capacity temperature limit of the torus (ATWS w/PCS failed)	Knowledge	1.3E-1	15 min	2E-1

taken directly from the ISAP study, where they were used in the station blackout analysis to evaluate offsite power recovery. The core melt time frames are in general agreement with the time frames used for the same scenarios in the IREP study. Using the TRC curve from NUREG/CR-2815, we get HEPs for the three cases for preventing core melt of 0.03, 0.003, and 0.0009. The HEP used for all cases in the ISAP study is the rule-based value of 0.013. While the ISAP value is clearly closer to the TRC values for Cases A and B than for Case C, there is virtually no effect on the final (dominant sequence) results. This is because ISAP grouped these three sequence scenarios together wherever they appeared and called it a siingle sequence (see, for example, sequence 2 on Table 3.1). The contribution from each of the three cases to these combined sequences is approximately equal in the ISAP study, (i.e., the three ways of reaching the point where this decision is required; failure of S/RVs to reseat, failure of IC, and failure of IC makeup; each contributes approximately one-third of the sequence probability up to that point). Thus, the average of the three HEP values mentioned above (which is equal to 0.011) is a reasonable approximation of the composite HEP. Clearly, then, using another approach yields the same final result, and we can conclude from this that the value used for this extremely important cognitive error is reasonable. Our only restriction would be that we would consider Case A to be more important, based on the TRC values, than the other cases, whereas the ISAP study would consider them equal. This would be significant if changes were being considered to reduce the frequency of these sequences which did not affect all three cases equally.

The next error shown in Table 2.12 is significant in that it considers cognitive operator error of commission. That is, the operator takes an action which is detrimental to the mitigation of an accident due to his misinterpretation of plant conditions. This type of error is seldom considered in a risk assessment, although it has the potential to be significant. The values used in the ISAP study are reasonable for screening purposes given that we expect that the operator will have approximately 30 minutes to recover from the erroneous action. From the NUREG/CR-2815 TRC curve, 30 minutes corresponds to an HEP of 0.01. This must be combined with the HEP for initially making the error. Even if this were as high as 0.1, which is doubtful, the total expected HEP would be 0.001. Thus, we expect that the values used in the ISAP study are probably conservative and yet they do not have a significant effect on the results. Therefore, further detailed analysis is not warranted.

The next two cognitive errors involve response to ATWS with PCS available. The first action is somewhat complex in total, i.e., many actions are required, but the only task which is essential in the immediate term is to trip the recirculation pumps. If the operator succeeds in doing that, the PCS will automatically maintain adequately safe conditions until the other actions are completed. No HEP is available from NUREG/CR-2815 for a time frame this short however, it would seem that the HEP used in the ISAP study is a reasonable screening number. This is because the action is an automatic response to observing that rod bottom lights for the control rods are not present. It is an intuitive rather than diagnostic/interpretative action, and an HEP of about 1 in 100 trials seems reasonable. For the second error, the result appears conservative since the operator would have a long time to provide for decay heat removal. However, this error does not contribute to core melt, and so it is sufficient to note that we do not feel that it is too low.

The final two errors in Table 2.12 pertain to operator diagnosis of the need to take certain actions during an ATWS with the PCS unavailable. While the actions are in some ways related, they are considered separately because the symptoms which direct the operator to enter each procedure are independent. That is, the procedure the operator enters to reduce core power does not specifically direct the operator to the containment temperature control procedure. The need to perform those actions must be realized separately. Again, for the actions required within three minutes, which are very complex and cannot be delayed as in the ATWS with PCS available case, no NUREG/CR-2815 values can be obtained. However, on an intuitive basis the value used is not unreasonable. We would expect that the operator would recognize the ATWS very quickly and have some time to decide on a proper course of action. Thus, the ISAP study number is generally reasonable. For the other operator decision required (torus heat capacity), the ISAP study value used is in general agreement with the value obtained from the NUREG/CR-2815 TRC curve. We do note that the ATWS rule uses a value of 0.5 as the HEP for the operator failing to initiate the procedures in time. This value includes both of the cognitive errors discussed above. The total ISAP study HEP for both errors is .26, only a factor of two smaller than the

ATWS rule number. This also supports the ISAP study values, since the generic value in the rule is generally recognized as being somewhat conservative.

2.4.2 Procedural Error Modeling

In addition to cognitive errors, the ISAP study also considered procedural errors. These are the errors which take place after the operator has diagnosed the situation, has selected the proper procedure, and is actually trying to perform the required actions. These errors were evaluated at the systems level (i.e. essentially considered in the system fault trees) as was done in the IREP study.

As far as we can ascertain from the limited information available, the ISAP study used two HEP values for procedural errors. A HEP of 0.0013 was used for control room actions involving simple manipulations or systems with which the operators are very familiar. An HEP of 0.013 was used for actions outside the control room or for control room actions which were complex or unfamiliar. These values are essentially identical to the suggested screening values for procedural error given in NUREG/CR-2815 (0.001 for procedural error with recovery potential, common for control room actions, and 0.01 for procedural error without recovery potential, common for actions outside the control room). Thus, these values appear reasonable, and our review indicates that these errors have very little effect on the results.

The one notable exception to this general conclusion is for ATWS with PCS unavailable. As noted in the previous section, the cognitive error modeling for this scenario is reasonable. However, despite the fact that the required actions to reduce water level are complex, no consideration was given to procedural error. The only procedural error considered was failure to properly initiate SLCS (0.013) which is the simple part of the procedure. The ATWS rule gives a HEP value of 0.1 in this situation for failing to reduce power properly while maintaining RPV water level above the top of active fuel. Thus, we believe that this procedural error could be a measurable contributor to ATWS core melt, and its exclusion in the ATWS analysis is unacceptable. In the absence of a detailed analysis, it is our opinion that a screening value of 0.13 should have been used for this error. The significance of this conclusion is discussed in Section 3.3. .pa

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3.0 RESULTS AND INSIGHTS INTO MAJOR CONTRIBUTORS TO THE CORE MELT FREQUENCY

In this section, a comparison between the results of the ISAP and IREP studies will be presented. This is done by performing a detailed comparison between the ISAP and IREP dominant accident sequences to find out the major differences between similar sequences and the significance of these differences with respect to the overall core melt frequency associated with the operation of the plant. This comparison is presented in Section 3.1. The results of this analysis are used in Section 3.2 to provide overall insights into the major contributors to the ISAP core melt frequency. Section 3.3 focuses on a few areas where changes to the current system configurations or procedures could conceivably result in major impacts on the plant's dominant accident sequences and overall core melt frequency.

3.1 Comparison Between ISAP and IREP Dominant Accident Sequences

To better understand the major contributors to the core melt frequency at the system level, a detailed analysis of the most dominant ISAP core melt sequences was performed. This was done examining the ISAP study dominant core melt sequences and comparing them with the corresponding IREP study dominant core melt sequences. The analysis was performed by comparing the sequence of events, the effect of methodologies on identifying the sequence of events, and the core melt frequency. With respect to core melt frequency, the ISAP study calculations used mean component failure data whereas the IREP study calculations used median values. To compare the sequence frequencies in the two studies, a simple conversion factor was used to convert the IREP study results to mean values based on the following argument. Most of the generic component failure probabilities have been developed by assuming that the components have a log-normal failure rate distribution. These data in most cases have an error factor of either 3 or 10. For components with an error factor of 3, the mean value is 1.25 times the median value. For components with an error factor of 10, the mean value is 2.66 times the median value. Since the components contributing to failure of different systems are a combination of those with an error factor 3 and 10, a multiplier of 2 was used to convert the median IREP study core melt frequencies to mean values. Note that the objective of comparing similar ISAP study and IREP study core melt frequencies is to identify those sequences that have large (order of magnitude) differences and focus on the

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basic reasons for these kinds of difference. With the level of uncertainty associated with most component failure data, much finer comparison does not provide any meaningful insights. With this fact in mind, Table 3.1 presents the dominant accident sequences found in the ISAP study along with the corresponding IREP study dominant accident sequences. The sequences are grouped by their common initiator where the ISAP study sequence numbers in the first column correspond to the sequence numbers identified in Table 5.3-5 of the Millstone Unit 1 Probabilistic Safety Study (2). A brief analysis of each sequence follows.

For sequence number 2, the ISAP and IREP sequences are fairly similar. The frequency of the ISAP sequences is lower than IREP sequences principally due to reductions in the failure probabilities of several components, namely, the diesel generator, gas turbine, and AC breakers previously shown in Table 2.10. In addition, modification to LNP logic circuits to eliminate single relay failures, and to IC makeup to remove AC dependency from the makeup admission/control valve, also helped to reduce the sequence frequency.

The same comments are applicable to sequence number 3 except that the LNP logic modifications have no effect here. Also, changes in the emergency operating procedures have reduced the chance of operator error in failing to depressurize the Reactor Pressure Vessel (RPV) and use the available low pressure pumps.

In sequence number 8, the contribution to core melt frequency is similar in both the ISAP and IREP studies. Competing differences have opposite effects. Reduction in failure rates of the gas turbine and switchgear breakers and a modification to the IC makeup admission valve power supply tend to reduce the frequency of the ISAP sequences. However, a change in the alternate Shutdown Cooling (SDC) system success criterion, which requires both trains of the Low Pressure Coolant Injection (LPCI) system and all four Emergency Service Water (ESW) pumps, increases the frequency of the ISAP sequence. The change in the success criterion of the alternate SDC system has substantially (by about two orders of magnitude) increased the probability of failure of this system and its contribution to the total core melt frequency. This is one of the areas that will be discussed in more detail in Section 3.3.

Table 3.1 Comparison Between ISAP and IREP Dominant Accident Sequences

ISAP Sequences					IREP Sequences	
Seq. #	Initiator	Failure of Support Systems	Sequence Description	Frequency (Mean)	Sequence*	Frequency Median (Mean)
2	LNP	Station AC Blackout (Only DC buses are energized)	o Correct cognitive decision to initiate IC and restore normal power. o S/R valves reclose, IC is initiated, IC makeup fails and AC power not restored before CM initiates (i.e., within 90 minutes). OR S/R valves reclose, IC initiation and restoration fail, and AC power not restored before CM initiaes (i.e., within 45 minutes). OR S/R valve sticks open and AC power not restored before CM initiates (i.e., within 25 minutes).	(7.0E-5)	T_4LCEFG(9) T_4KCEFG(3) T_4JCEFG(2)	8.0E-5 (1.6E-4)
3	LNP	None OR AC Bus 14E	o Cognitive error in decision not to restore RPV level. o S/R valves reclose and auto IC initiation or IC makeup failed. OR S/R valve sticks open. o Auto FWCI initiation failed. Random failure for SS#1. Failure given (Q = 1) for SS#3. (No other auto system is available.)	(3.7E-5)	T_4KCD(4) T_4LCD(5) T_4JCD(1)	1.3E-4 (2.6E-4)
8	LNP	AC Bus 14E	o Correct cognitive decision to restore RPV level. o S/R valves reclose and initiation and restoration of IC or IC makeup fails. OR S/R valve sticks open. o FW fails (given). o Manual depressurization is successful.	(6.5E-5)	T_4KCMG(12) T_4LCMG(10) T_4CMG(8)	2.9E-5 (5.8E-5)

Table 3.1 Comparison Between ISAP and IREP Dominant Accident Sequences (continued)

ISAP Sequences					IREP Sequences	
Seq. #	Initiator	Failure of Support Systems	Sequence Description	Frequency (Mean)	Sequence*	Frequency Median (Mean)
8 (cont'd)			o Low pressure pumps inject. o Off-site AC power recovery fails. o 14E bus energized by cross-connection to diesel generator. o SDC fails. (Note: FW and circulating water pumps cannot be loaded on the diesel generator. Therefore, the main condenser is not credited. Also, both trains of the alternate SDC cannot be powered by the diesel.)			
15	LNP	AC Bus 14E	o Correct cognitive decision to restore RPV level. o S/R valves reclose. Initiation and restoration of IC or IC makeup fails. OR S/R valve sticks open. o FW failed given (Q = 1.0) for SS#3. o Manual depressurization is successful. o Low pressure pumps inject. o Off-site AC recovery fails. o Energizing AC bus 14E by cross-connection fails. o SDC fails. (Note: The main condenser cannot be used unless FW is operating. Also, both trains of the alternate SDC cannot be powered by the diesel generator.)	(8.6E-6)	T_4KCMG(12) T_4LCMG(10) T_4JCMG(8)	2.9E-5 (5.8E-5)

Table 3.1 Comparison Between ISAP and IREP Dominant Accident Sequences (continued)

ISAP Sequences					IREP Sequences	
Seq. #	Initiator	Failure of Support Systems	Sequence Description	Frequency (Mean)	Sequence	Frequency Median (Mean)
9	LNP	AC Bus 14E	Same as in sequence #8, except: o Off-site AC power recovery succeeds. o Restoration of main condenser and IC makeup fails. (The latter is credited only in sequences where the S/R valves have reclosed.) o SDC and alternate SDC fail.	(4.0E-5)	None	
	LNP		Total	(2.20E-4)		2.39E-4 (4.78E-4)
7	Small Break LOCA	None	o Blowdown steam condensers in torus as vacuum breakers remain closed. o FW continues to run and maintains RPV level for short time until it trips on low hotwell level. o Correct cognitive decision to switch to low pressure pumps. o Core spray pumps inject and operator correctly maintains RPV level. o Containment cooling (i.e., torus cooling) fails. (No other system is adequate to provide long-term decay heat removal following a small break.)	(1.6E-4)	(ILB)CG (ISB)CEG	≤E-6
1	Loss of Feedwater	None	o S/R valves reclose and auto IC initiation fails. OR S/R valve sticks open. o Cognitive error in decision not to restore RPV level. (No other auto system is available.)	(7.6E-5)	T_3KD T_3JD	≤E-6

Table 3.1 Comparison Between ISAP and IREP Dominant Accident Sequences (continued)

ISAP Sequences					IREP Sequences	
Seq. #	Initiator	Failure of Support Systems	Sequence Description	Frequency (Mean)	Sequence	Frequency Median (Mean)
12	Loss of Feedwater	None	o S/R valves reclose, auto initiation of IC and IC makeup fails. OR S/R valve sticks open. o Correct cognitive decision to restore RPV level. o Restoration of IC or IC makeup fails (credited only in sequences where S/R valves reclose). o Restoration of FW fails. o Manual depressurization is successful. o Low pressure pumps inject. o SDC and alternate SDC fail.	(2.1E-5)	T_3KMG T_3LMG T_3JMG	≤E-6
	Loss of Feedwater		Total	(9.7E-5)		≤E-6
4	Reactor Transients	None OR AC Bus 14E	o FW fails to run post scram. Random failure for SS#1. Failure given (Q = 1) for SS#3. o Cognitive error in decision not to restore RPV level. o S/R valves reclose and auto IC initiation or IC makeup fails. OR S/R valve sticks open.	3.5E-5	$T_{1,2}$KCD $T_{1,2}$LCD $T_{1,2}$JCD	≤E-6
11	Reactor Transients	None OR AC Bus 14E	o FW fails to run post scram. Random failure for SS#1. Failure given (Q = 1) for SS#3. o Correct cognitive decision to recover RPV level. o FW restoration fails.	(3.2E-5)	$T_{1,2}$KCMG $T_{1,2}$LCMG $T_{1,2}$JCMG	(≤E-6)

Table 3.1 Comparison Between ISAP and IREP Dominant Accident Sequences (continued)

ISAP Sequences					IREP Sequences	
Seq. #	Initiator	Failure of Support Systems	Sequence Description	Frequency (Mean)	Sequence	Frequency Median (Mean)
#11 (cont'd)			Random failure for SS#1. Failure given (Q = 1) for SS#3. o S/R valves reclose. Initiation and restoration of IC and IC makeup fails. OR S/R valve sticks open. o Manual depressurization is successful. o Low pressure pumps inject. o AC bus 14E energized by cross-connection (credited only for SS#3 case). o SDC and alternate SDC fail.			
16	Reactor Transients	None	o FW continues to operate post scram. o The main condenser is isolated as a heat sink due to MSIV closure post scram. o S/R valves reclose, initiation and restoration of IC or IC makeup fails. OR S/R valve sticks open. o Restoration of the main condenser fails. o SDC and alternate SDC fail.	(4.5E-5)	T_2KMG T_2HLMG(21) T_2JMG	2.0E-6 (4.0E-6)
5	Reactor Transients	AC Bus 14E and 14F. Both fail to fast transfer post scram, i.e., station AC blackout - only DC buses (both) energized.	o FW fails (given). o Correct cognitive decision to restore and stabilize RPV. level. o S/R valves reclose and initiation and restoration of IC or IC makeup fails. OR S/R valve sticks open. (No other system is available.)	1.4E-5	$T_{1,2}$KCEFG $T_{1,2}$LCEFG $T_{1,2}$JCEFG	≤E-6
	Reactor Transients		Total	1.26E-4		2.0E-6 (4.0E-6)

Table 3.1 Comparison Between ISAP and IREP Dominant Accident Sequences (continued)

ISAP Sequences					IREP Sequences	
Seq. #	Initiator	Failure of Support Systems	Sequence Description	Frequency (Mean)	Sequence	Frequency Median (Mean)
6	Small-Small Break LOCA	None	o Blowdown steam condenses in torus as vacuum breakers remain closed. o FW continues to run post scram. o Cognitive error in decision not to start condensate transfer pump (to replenish the hotwell) or use low pressure pumps. o FW eventually trips on low hotwell level (given).	6.9E-6	(SB)CD	≤E-6
14	Small-Small Break LOCA	None	o Blowdown steam condenses in torus as vacuum breakers remain closed. o FW continues to run post scram. o Correct cognitive decision to start emergency condensate pump. o Emergency condensate pump starts and transfers inventory from the CST to the hotwell. o Operator fails to disregard the indicated level when the drywell temperature reaches the RPV saturation temperature and therefore prematurely terminates or throttles injection.	1.35E-5	(SB)CD	≤E-6
18	Small-Small Break LOCA	None	o Blowdown steam condenses in torus as vacuum breakers remain closed. o FW continues to operate post scram. o Correct cognitive decision to start emergency condensate transfer pump. o Emergency condensate transfer pump starts and transfers inventory from the CST to the hotwell.	8.3E-6	(SB)MG	≤E-6

3F2

Table 3.1 Comparison Between ISAP and IREP Dominant Accident Sequences (continued)

ISAP Sequences					IREP Sequences	
Seq. #	Initiator	Failure of Support Systems	Sequence Description	Frequency (Mean)	Sequence	Frequency Median (Mean)
18 (cont'd)			o Correct cognitive decision to disregard the indicated RPV level when the drywell heats up to RPV saturation temperature. o Restoration of the main condenser fails. o SDC and alternate SDC fail.			
	Small-Small Break LOCA		Total	2.87E-5		≤E-6
10	Loss of Service Water System	None except the SWS	o Correct cognitive decision to restore RPV level. o S/R valves reclose, initiation and restoration of IC or IC makeup fails. OR S/R valve sticks open. o Manual depressurization is successful. o Low pressure pumps inject. o Alternate SDC fails. (Note: both FW and SDC are unavailable due to loss of SW.)	3.4E-5	T_3KMG T_3^{LMG} T_3MG	≤E-6
17	Inadvertent Opening of a Safety/Relief Valve	None	o FW continues to operate post scram. o MSIVs close post scram due to low pressure, isolating the main condenser as a heat sink. o Restoration of the main condenser fails. o SDC and alternate SDC fail.	1.9E-5	T_5HMG T_5^{MG}	≤E-6

3f3

Table 3.1 Comparison Between ISAP and IREP Dominant Accident Sequences (continued)

ISAP Sequences					IREP Sequences	
Seq. #	Initiator	Failure of Support Systems	Sequence Description	Frequency (Mean)	Sequence	Frequency Median (Mean)
13	Large Break LOCA	None	o Blowdown steam condenses in torus as vacuum breakers remain closed. o ECCS signal is generated. o Core spray pumps start and inject automatically. o Correct operator decision to disregard indicated high level when the drywell heats up to RPV saturation condition. o Containment cooling (i.e., torus cooling) fails. (No other system is adequate to provide long-term decay heat removal following a large break.)	1.6E-5	(LLB)G	≤E-6

*Numbers in parentheses indicate IREP sequence core melt ranking from IREP study.

Sequence number 15 is very similar to sequence number 8, so the same comments apply.

For ISAP sequence number 9, there is no equivalent IREP sequence. This is due to the fact that the IREP study did not treat situations where an LNP followed by recovery of offsite power could result in core melt. The assumption was made in the IREP study that recovery of the offsite power would successfully terminate the sequence. Consideration of this scenario in conjunction with the increased failure rate of the alternate SDC system in the ISAP study have made this sequence dominant.

Overall, the LNP sequences in the ISAP and IREP studies are fairly similar. When there are differences in the frequency of similar core melt sequences, they are principally due to either the lower plant-specific component failure probabilities for the diesel generator, gas turbine, and AC circuit breakers or higher unavailability for the alternate SDC system due to the revised success criterion for this system.

The next sequence in Table 3-1 is the Small Break LOCA, sequence number 7. This ISAP break size combines the IREP intermediate breaks with the upper end of the IREP small breaks. The contribution from this sequence is dominant in the ISAP study because of the change in the success criterion for containment cooling (alternate SDC system) which was mentioned previously.

The next two sequences are initiated by loss of the feedwater system. In sequence number 1, the IREP study treated recovery of feedwater and the use of manual depressurization with low pressure pumps as two distinct operator actions. The ISAP study considered the cognitive-based error of the operator failing to make the correct diagnosis of the need to restore RPV level. This linked the two actions to a single root cause, which resulted in a higher combined failure probability in the ISAP study. This was somewhat counteracted by a decrease in initiating event frequency, but the combined effect was to make this sequence dominant.

It is important to note that inclusion of cognitive human error on the event trees is one of the major differences between the ISAP and IREP accident sequence development methodology. As mentioned above, this change has resulted in a larger combined human error probability with a significant effect on the dominant accident sequences and overall core melt frequency. Another important point about this sequence is the need for manual depressurization of the RPV before any low pressure pumps can be used. The automatic depressurization at Millstone Unit 1 requires coincident indication of low-low RPV level, high drywell pressure, and a two minute persistance of the low-low water level. In addition, there must be an indication of at least one low pressure ECCS pump running. Thus, in all the non-LOCA sequences where there would be no high drywell pressure, the automatic depressurization will not be initiated. This implies that if there is an operator cognitive error in restoring the RPV level, the whole low pressure injection system consisting of the LPCI and core spray pumps would be defeated. This brings up the possibility of addition of an automatic depressurization capability for non-LOCA sequences, which is another area discussed in more detail in Section 3.3.

The progression of events in sequence number 12, which is the second loss of feedwater sequence, is very similar in the ISAP and IREP studies. The main difference in the sequence frequencies is due to the higher failure probability of the alternate SDC system, discussed earlier.

The next four sequences are reactor transient sequences. In sequence number 4, the progression of events in the ISAP and IREP sequences is similar. The major reason that the ISAP sequence is more dominant is the cognitive human error in failing to restore the RPV level which combines several human error failures that are considered separately in the IREP sequences. This was discussed previously for sequence number 1. The higher probability of failure assigned to this cognitive error is the prime contributor to its higher frequency in the ISAP study.

In sequence number 11, the ISAP and IREP accident sequences are similar. The main reason for higher core melt frequency in the ISAP study is the higher unavailability associated with the alternate SDC system discussed before.

Sequence number 16 is affected by a number of competing differences. First, the initiating event frequency of the transient is lower in the ISAP study. Also, the IREP study did not give credit for recovering the main condenser due to limitations in the MSIV equalizing lines which prevented equalizing differential pressure on the valve disks within a reasonable time. A modification to enlarge those lines has been accomplished, allowing the ISAP study to take this credit. These differences tend to reduce the contribution of these sequences. However, this is more than counteracted by the increase in alternate SDC system failure rate due to the change in the success criterion, which increases the overall contribution of the sequence.

The last transient sequence is sequence number 5. The main difference between the two studies is that the IREP study did not treat the possibility of station blackout for sequences not initiated by loss of normal power, assuming instead that the contribution was not significant. Consideration of this possibility in the ISAP study caused this sequence to become dominant.

The next three sequences are small-small break LOCAs. This initiator in the ISAP study represents an approximate break size resulting in at least 2.5 gpm leakage up to an approximate break diameter of 1.35 inches. This break size represents the lower end of the IREP small break, which includes break diameters of up to approximately 5.24 inches. The frequency of occurrence of the small-small break LOCA in the ISAP study is an order of magnitude larger than the small break frequency in the IREP study. Breaks in the lower end of this range require manual initiation of depressurization because high drywell pressure does not occur. In addition, the IREP study assumption that the condensate transfer pumps (CTP) would start automatically is not entirely correct. The high flow emergency CTP is required for these breaks, and must be started manually. In sequence number 6, both of these actions are coupled by a cognitive-based error (similar to sequence number 1). The high initiation frequency for this sequence along with the need for manual depressurization and start of condensate transfer pumps, which are coupled in one cognitive human error, have resulted in a high sequence frequency compared to that found in the IREP study.

In sequence number 14, operator error of commission in misdiagnosing the plant conditions and taking an action to terminate a safety system prematurely was considered in the ISAP study. The IREP study did not adequately treat this type of error. Consideration of this type of human error along with a much higher initiator frequency resulted in a more dominant sequence compared to the IREP study sequences.

In sequence number 18, the ISAP study includes a failure to restore the main condenser. As previously mentioned, the IREP study concluded that restoration of the main condenser after isolation was not practical but credit was given for this action in the ISAP study due to a plant modification. This credit is compensated for by a higher initiating frequency and higher failure probability for the alternate SDC system, making this sequence more dominant than the IREP study sequence.

Overall, the higher initiating frequency, the combined cognitive error in performing depressurization and startup of condensate transfer pumps, the consideration of operator error of commission in misdiagnosing the plant condition, and the higher alternate SDC system failure probability result in higher frequency small-small break LOCAs in the ISAP study compared with the IREP small break LOCA sequences.

In sequence number 10 the ISAP study gave credit for recovery of the Service Water System (SWS) only in the short term, including it in the initiator frequency. This results in the complete unavailability of the SDC system for all LOSW sequences, and greatly increases this sequence's contribution compared to the IREP study. The IREP study gave substantial credit for long-term SWS recovery, allowing for the SDC system to be used. Additionally, the ISAP success criteria for SWS following a trip are more restrictive than that used in the IREP study, resulting in an overall increase in the frequency of the loss of service water in the short term. Combining this with an increased alternate SDC failure rate due to a change in its success criteria made this sequence dominant.

In sequence number 17, several competing effects result in the ISAP sequence being more dominant. The initiating event frequency in the ISAP study is significantly lower than the IREP study due to a plant modification and installation of more reliable safety/relief valves. This reduction in initiator frequency is opposed by two factors. First, in the ISAP study, it was assumed that the main condenser would be initially lost, whereas in the IREP study it was assumed it could continue to run post-scram. Second, there is a higher failure probability of alternate SDC system in the ISAP study. The combined effect of these factors is to make the ISAP sequence more dominant than the IREP sequence.

The last dominant accident sequence in Table 3.1 is sequence number 13, initiated by a large break LOCA. The sequence of events in the ISAP and IREP studies is very similar in this case. The primary reason for a more dominant ISAP sequence is the higher failure probability of the containment cooling (alternate SDC system).

In the next section a summary of the major contributors to the ISAP core melt frequency will be presented.

3.2 Insights into Major Contributors to the Core Melt Frequency.

In the last section, a detailed comparison between the ISAP and IREP studies dominant accident sequences was presented. This comparison provided some insights into changes, both systemic and procedural, that have taken place at Millstone Unit 1 since the original IREP study was performed, and the significance of these changes with respect to dominant accident sequences and the overall core melt frequency. Figure 3.1 shows the contribution of major classes of initiators to the total core melt frequency in both studies. The principal reasons for changes in the dominant contributors were explained in the last section during the discussion of individual dominant sequences. To put the results in better perspective, a summary of these differences by the major classes of initiators identified in Figure 3.1 is presented here. More detail on these differences can be found in the appropriate sections in this report.

1. Loss of Normal Power (LNP); Overall decrease in the ISAP study vs the IREP study core melt contribution.

   Reasons for this decrease:

   a. Reductions in failure rate data of the diesel generator, gas turbine generator, and switchgear breakers.

   b. Modification to LNP logic to eliminate single relay failures.

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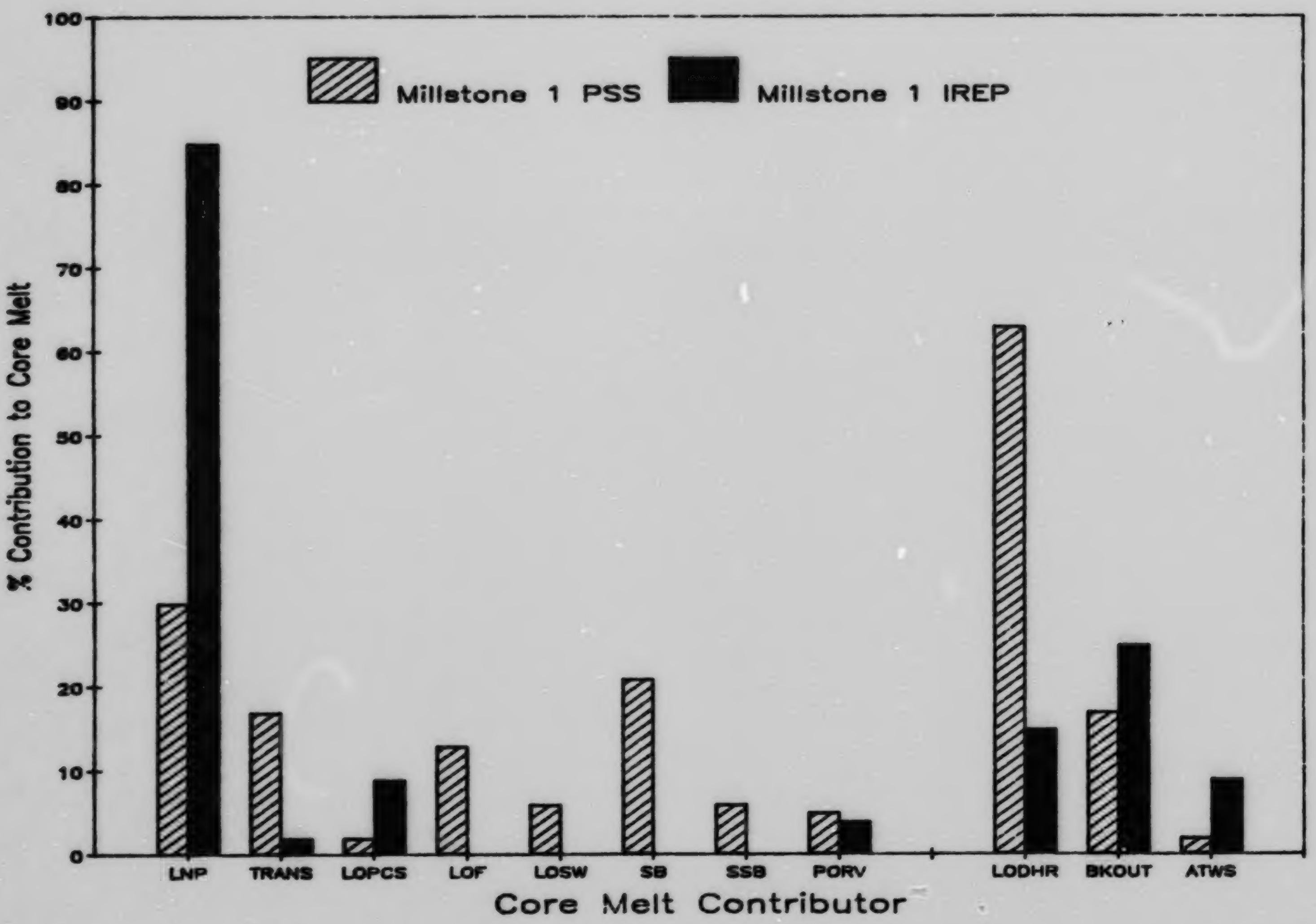

Figure 3.1 Comparison Between Dominant ISAP and IREP Contributors to the Core Melt Frequency.

c. Modification to IC makeup to eliminate admission valve AC dependency.

d. Change to symptom-oriented procedures eliminated confusing procedure for initiating manual depressurization when required, reducing human error probability.

The only mitigative factor that limited the amount of decrease in the ISAP study core melt contribution was an increase in the failure probability of the alternate SDC system due to changes in its success criterion.

2. Transients (TRANS); Overall increase in the ISAP study vs the IREP study core melt contribution.

Reasons for this increase:

a. Cognitive error modeling and symptom-oriented procedures linked failure to restore FW and failure to depressurize to a single decision process, increasing overall probability of human error and recovery failure.

b. Consideration of the possibility of loss of normal power following a non-LNP initiating event.

c. Increase in failure rate of alternate SDC system due to change in success criteria.

Mitigative factors which limited amount of increase:

a. Decrease in initiating event frequency.

b. Modification to MSIV equalization lines allowing for recovery of main condenser for cooling.

3. Loss of Power Conversion System (LOPCS); Overall decrease in the ISAP study vs the IREP study core melt contribution.

   Reasons for this decrease:

   a. Reduction of initiating event frequency.

   b. Modification to MSIV equalization lines allows for recovery of main condenser for cooling.

The only mitigating factor that limited the amount of decrease in the ISAP study core melt contribution was the increase in the failure probability of the alternate SDC system due to changes in its success criteria.

4. Loss of Feedwater (LOF); Overall increase in the ISAP study vs the IREP study core melt contribution.

   Reasons for this increase:

   a. Cognitive error linkage between recovery of FW and failure to depressurize.

   b. Increase in alternate SDC failure rate.

The only mitigative factor that limited the increase in the ISAP core melt contribution was the reduction in the initiator frequency.

5. Loss of Service Water System (LOSW); Overall increase in the ISAP study vs the IREP study core melt contribution.

   Reasons for this increase:

   a. No long term recovery credit for service water system.

   b. Increase in alternate SDC system failure rate.

   c. Increase in frequency of short-term LOSW due to change in success criteria.

6. Small Break LOCA (SB); Overall increase in the ISAP study vs the IREP study core melt contribution.

   The principal reason for the increase in the ISAP core melt contribution is the increase in failure probability of the alternate SDC system.

7. Small-Small Break LOCA (SSB); Overall increase in the ISAP study vs the IREP study core melt contribution.

   Reasons for this increase:

   a. Special consideration of breaks which do not actuate Automatic Pressure Relief (APR) because no high drywell pressure would be present, requiring operator action to depressurize.

   b. Need for operator action to start high-capacity emergency condensate transfer pumps to supply sufficient flow to the hotwell.

   c. Cognitive error modeling and symptom-oriented procedures link the above two actions to a single decision process.

   d. Consideration of cognitive error of commission in prematurely terminating injection due to misinterpretation of instrumentation.

   e. Increase in initiating event frequency.

The only mitigative factor that limits the amount of increase in the ISAP core melt contribution is the credit allowed for providing long-term cooling with the condenser or SDC system due to low break flow rate.

8. Inadvertent Opening of Power Operated Relief Valve (PORV); No major change between the two studies core melt contribution due to several compensating effects.

   Factors resulting in an increase in the ISAP study the core melt contribution:

   a. Increase in alternate SDC system failure rate.

   b. Automatic loss of condenser due to low pressure (pressure cannot be kept up after trip).

   Factors resulting in a decrease in the ISAP study core melt contribution:

   a. Credit allowed for recovery of condenser due to equalization line modification.

   b. Initiating event frequency reduced due to modification to install more reliable valves.

In addition to the above classes of initiators, three groups of events are also compared in Figure 3.1. The first one is the group of events leading to core melt that include Loss of Decay Heat Removal (LODHR) function. In this case, the ISAP dominant sequence frequencies have increased substantially due to the increased failure probability of the alternate SDC system as a result of the change in its success criteria.

The second group is the Station Blackout (BKOUT) sequences. In this case the ISAP dominant sequence frequency has decreased due to:

1. Reductions in failure rate data of diesel and gas turbine generators and switchgear breakers.

2. Modifications to LNP logic to eliminate single relay failures.

3. Modifications to IC makeup to eliminate admission valve AC dependency.

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The last group of events shown in Figure 3.1 is the Anticipated Transients Without Scram (ATWS) sequences. The overall ISAP core melt contribution in this case has decreased due to credit allowed for operator action to initiate the standby liquid control system (43 gpm) and to take other actions to mitigate the event. This decrease was limited by a significant increase in the RPS failure probability, based on a simple statistical analysis. This event was assumed to lead to core melt in the IREP study. This assumption is one of the topics that will be discussed in more detail in the next section.

3.3 Discussion of Several Areas of Plant Vulnerability

In this section, three areas with significant contributions to the core melt frequency are discussed in detail. These areas were chosen for more detailed discussion because they are areas where changes in the system configuration or procedures can result in substantial reductions in their contribution to the core melt frequency.

The first area is the reliability of the alternate SDC system. Referring to Figure 3.1, it can be seen that sequences involving loss of the decay heat removal system contribute to about 65% of the ISAP study total core melt frequency. This contribution is substantially higher in the ISAP study than in the IREP study. As mentioned previously, this increase is primarily due to the higher failure probability associated with the alternate SDC system. The increase in the failure probability of the alternate SDC system is due to the change in its success criteria.

In the IREP study, the success criterion for this system consists of successful operation of one LPCI pump and the associated containment cooling heat exchanger with one Emergency Service Water (ESW) pump removing heat from the heat exchanger. Based on thermal hydraulic calculations performed by the licensee for the PSS, the success criteria for the systems were changed in the ISAP study by requiring two LPCI containment cooling heat exchangers with one LPCI pump per heat exchanger and all four emergency service water pumps to remove the heat from the containment cooling heat exchangers. This change has dramatically increased the failure probability of this system.

To assess some alternatives in reducing the failure probability of this system, the detailed fault tree for this system, shown in Figure 3.2.24-2 of the Millstone Unit 1 PSS, was simplified and is shown in Figure 3.2. Based on the current configuration, the failure probability of this system with no support system failure is 0.148. Three scenarios for improvement in the reliability of this system were examined. In the first case, it was assumed that the LPCI/containment cooling loops are made redundant. In the second case, it was assumed that the emergency service water loops are made redundant. In the third case, it was assumed that both of the above improvements were incorporated. Table 3.2 shows the results of these evaluations. Incorporation of redundancy in the LPCI system alone resulted in the reduction of the failure probability of the alternate SDC by a factor of about 1.7. The effect of making the ESW loop redundant is a reduction in the failure probability of the alternate SDC system by a factor of about 2.2. If both of these changes are incorporated, the failure probability of this system can be reduced by a factor of about 40. As was mentioned earlier, 65% of the ISAP core melt frequency was due to failure of long-term decay heat removal. Assuming that both the LPCI and ESW loops are made redundant results in a reduction in the ISAP study core melt frequency from 8.07×10^{-4} to 2.95×10^{-4}, a reduction of about a factor of 3.

Using NRC's $1000/man-rem guidelines, the following relationship can be used to suggest an approximate level of expenditure that would be justified for any type of corrective action that could lead to a reduction in core melt frequency:

$$E = CM * MRR * \frac{\$1000}{\text{man-rem}} * Y \qquad (3.1)$$

where

E = The expenditure that is justified for the specific correction
CM = Change in core melt frequency as a result of the correction
MRR = Man-rem release that could occur as a result of a core melt accident and containment failure at the plant under consideration
$\frac{\$1000}{\text{man-rem}}$ = $1000 per man-rem NRC guideline
Y = Number of years left in the life of the plant

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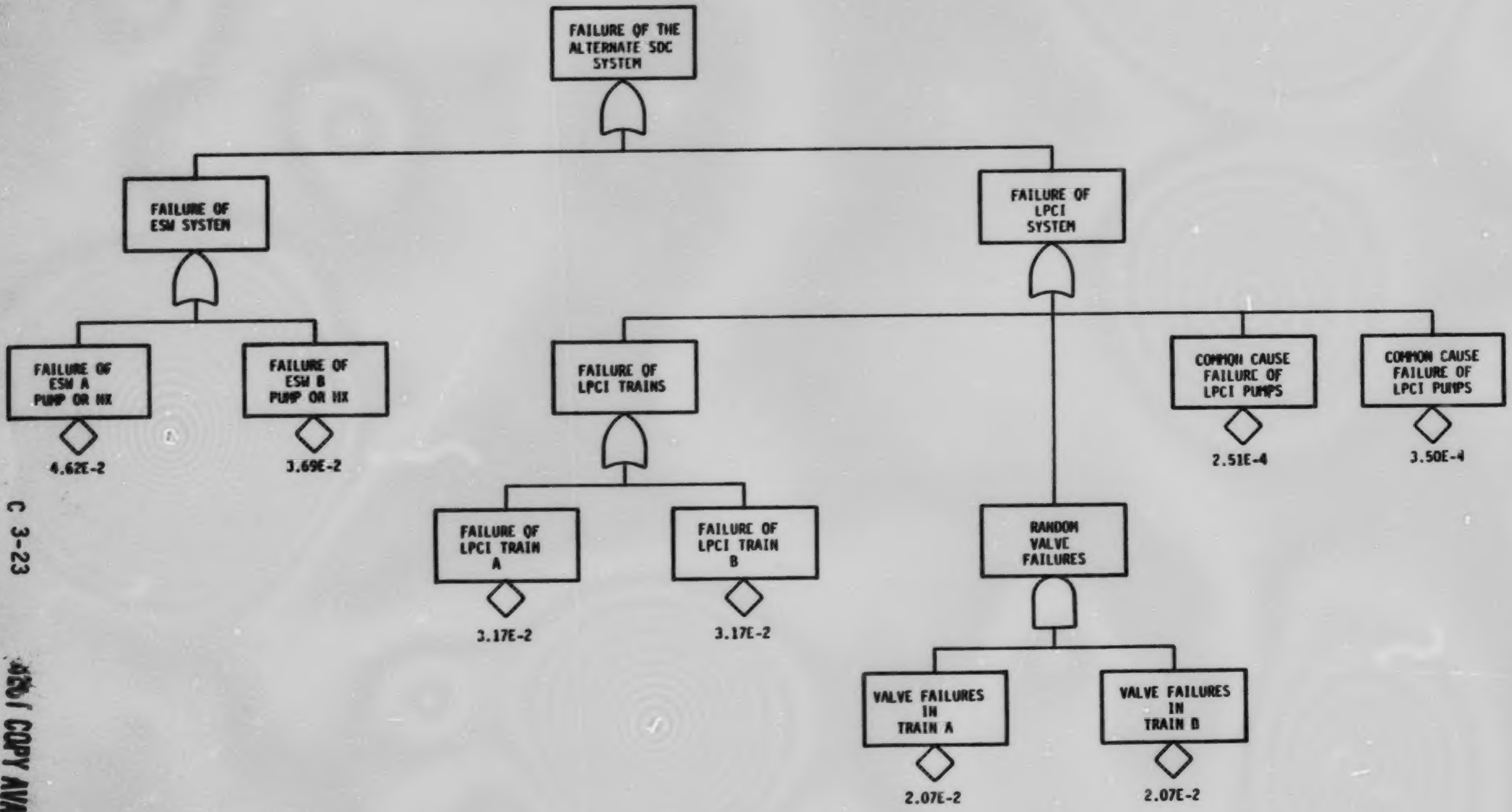
FAILURE OF THE ALTERNATE SDC SYSTEM
FAILURE OF ESW SYSTEM
FAILURE OF LPCI SYSTEM
FAILURE OF ESW A PUMP OR HX
4.62E-2
FAILURE OF ESW B PUMP OR HX
3.69E-2
FAILURE OF LPCI TRAINS
COMMON CAUSE FAILURE OF LPCI PUMPS
2.51E-4
COMMON CAUSE FAILURE OF LPCI PUMPS
3.50E-4
FAILURE OF LPCI TRAIN A
3.17E-2
FAILURE OF LPCI TRAIN B
3.17E-2
RANDOM VALVE FAILURES
VALVE FAILURES IN TRAIN A
2.07E-2
VALVE FAILURES IN TRAIN B
2.07E-2

Figure 3.2 Simplified Fault Tree for the Failure of Alternate SDC System

Table 3.2 UNAVAILABILITY OF THE ALTERNATE SHUDTOWN COOLING SYSTEM AS A FUNCTION OF DIFFERENT SYSTEM CONFIGURATIONS

System Configuration	Alternate Shutdown Cooling System Unavailability
1. Present	0.148
2. LPCI/Containment Cooling Loops Redundant	0.085
3. Emergency Service Water (ESW) Loops Redundant	0.066
4. Both LPCI and ESW Loops Redundant	0.37×10^{-2}

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For Millstone Unit 1, the utility has estimated a 3×10^6 man-rem release in the event of a core melt and containment failure. Also, 25 years was used as the number of years left in the life of the plant. Based on these values and a core-melt reduction of 5.12×10^{-4} as a result of changes to the alternate SDC system discussed above, approximately 38 million dollars of expenditure would be justified for these corrective actions.

The second area analyzed in more detail is the area involving those core melt sequences which require manual depressurization of the RPV. Depressurization is required in those events where the feedwater system is either unavailable or incapable of providing sufficient water to the core and therefore low pressure systems are needed to keep the core covered.

Millstone Unit 1 has an Automatic Depressurization System (ADS) which is initiated when there is a coincident indication of reactor water low-low level for two minutes, high drywell pressure and indication that at least one low pressure pump is running. Because of the requirement of high drywell pressure, automatic depressurization occurs only when a LOCA has occurred. In other cases, such as loss of feedwater or other types of transients and the lower range of small-small break LOCAs, depressurization does not occur automatically. In these sequences, if there is a cognitive operator error in not restoring the RPV level, the low pressure systems such as LPCI and core spray systems will be automatically defeated since the reactor pressure has to be below about 350 PSI before the pumps in these systems can inject into the core.

The ISAP study dominant accident sequences that include this type of cognitive human error, i.e., failure to depressurize the reactor manually, contribute to about 21% of the total core melt sequences. The most dominant sequence among these is the loss of feedwater transient that contributes about 9.5% of the total core melt frequency. If in these sequences there is the possibility of an automatic depressurization despite the cognitive operator error, the frequency of these core melt sequences will be reduced by the failure probability of the ADS.

The results of the analysis of the ADS in Millstone Unit 1 is given in Table 3.2.18-1 of the PSS. Based on this table, the failure probability of ADS with both DC buses available is 0.13. Currently the relay contacts in

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this system are never tested. If a more frequent (such as monthly) test of these relay contacts is performed, the failure probability of this system can be reduced by about two orders of magnitude.

Based on the present system configuration and procedures, inclusion of an automatic depressurization system in the ISAP study sequences which involve human error to depressurize the RPV will result in about an order of magnitude reduction in their contribution to the total core melt frequency. The net effect of this is a reduction of about 18% in the total ISAP study core melt frequency. Using equation 3.1, an approximate expenditure of 11 million dollars would be justified for this correction.

There could be several negative aspects associated with addition of an automatic depressurization option to these sequences. The first one is the possibility of early depressurization before all efforts in restoration of the feedwater system are exhausted. Another very important negative aspect could be the possibility of automatic depressurization after isolation condenser has been initiated and is successfully removing heat from the core. Thus, it is crucial that these negative aspects of addition of an automatic depressurization system for non-LOCA sequences are considered very carefully before any decision on this issue is made.

The final subject considered is the Anticipated Transients Without Scram (ATWS). Other sections of this report noted various areas related to ATWS which were believed to be deficient or to contain erroneous assumptions or conclusions. These areas were numerous enough that it was not easy to determine what effect they would have on the overall quantification of ATWS sequences. Therefore, it was necessary to requantify the ATWS event trees to get some idea as to what the core melt contribution from ATWS would be if these deficiencies were remedied.

One area could not be completely clarified. The ISAP study assumed that a 43 gpm SLCS was sufficient to mitigate an ATWS with condenser isolation (loss of PCS). While there is some reason to believe that this may be true, no plant-specific analysis was performed to verify this. The assumption was based on engineering judgment and extrapolation from analysis performed for other plants. The NRC's ATWS rule states that 43 gpm is not sufficient for this type of ATWS, based on a self-proclaimed conservative analysis. How conservative the analysis is and how plant-specific features at Millstone 1 might affect the analysis cannot be determined without a plant-specific analysis. Therefore, the ATWS trees have been requantified for two separate cases. Case 1 assumes that the 43 gpm SLCS is capable of mitigating an ATWS with condenser isolation, just as was done in the ISAP study. Case 2 assumes that the 43 gpm SLCS is not capable of mitigating an ATWS with condenser isolation, and thus all such ATWS events would lead directly to core melt. It should be noted that there is no question that the 43 gpm SLCS can mitigate an ATWS when the condenser is not isolated (PCS available) because of Millstone 1's 100% bypass capability.

The requantification of ATWS for Case 1 was performed with the following changes made from the ISAP study. These changes are discussed only briefly here, but generally reflect detailed comments made earlier in this report. The ATWS trees used for the requantification are shown on Figures 3.3 and 3.4.

- The PSS failure probability for the RPS was judged to be too conservative for the design of the Millstone 1 RPS. The probability was changed from 5.4E-5 to 1E-5, which was taken from the ATWS rule.

- The procedural HEP for initiating SLCS and lowering power by controlling RPV level was raised from 0.013 to 0.13. This increased the failure probability of event Y1 from 0.031 to 0.16.

- Even though it is assumed in this case that the 43 gpm SLCS is capable of mitigating an ATWS with the main condenser isolated, it is apparent that it is probably not capable of keeping the torus temperature below 176 degrees. This is the point at which the low pressure safety injection pumps lose sufficient NPSH. Thus, no credit should be allowed for these pumps and the failure probability of event E should be 1.0.

- The PSS assumed that both the SDC system and torus cooling were required to prevent core melt. Torus cooling is not actually required for an extremely long time since initiation of SDC stops torus heatup. Therefore, the assumption that both are required is

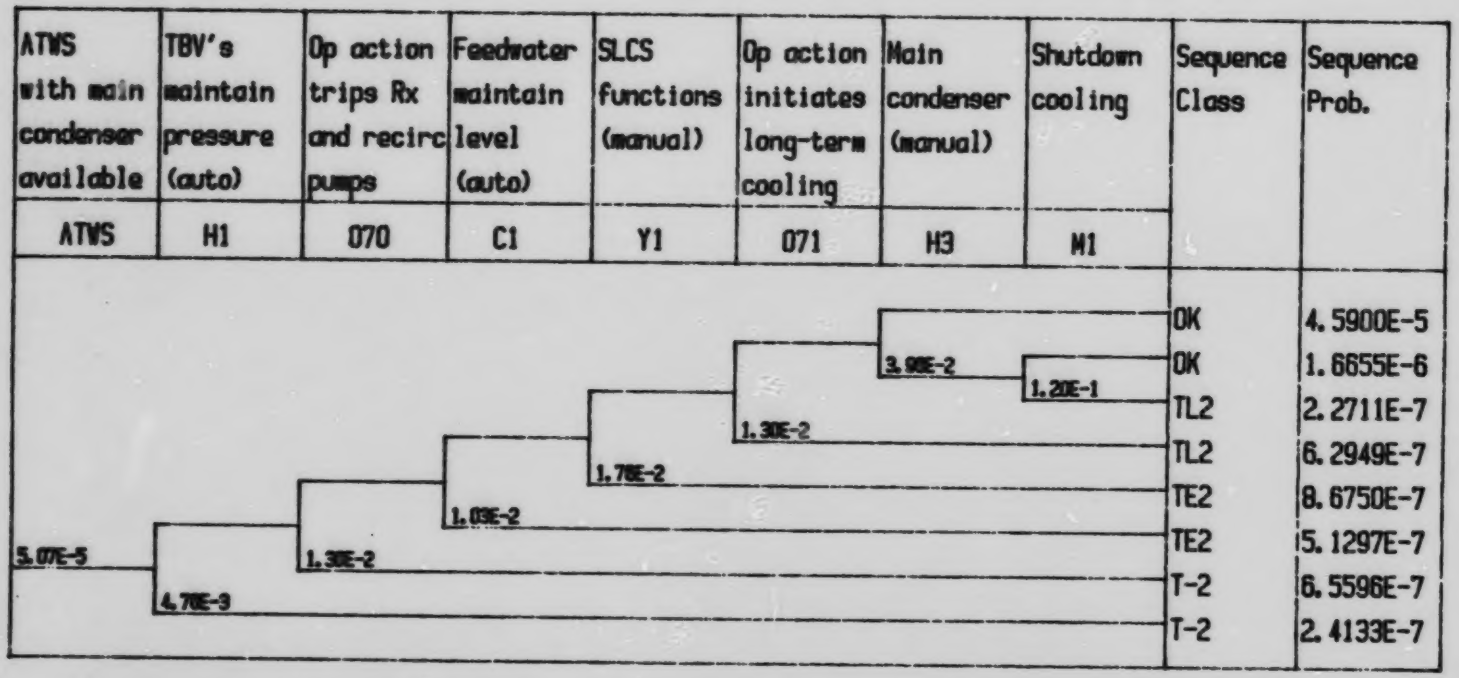
ATWS with main condenser available
TBV's maintain pressure (auto)
Op action trips Rx and recirc pumps
Feedwater maintain level (auto)
SLCS functions (manual)
Op action initiates long-term cooling
Main condenser (manual)
Shutdown cooling
Sequence Class
Sequence Prob.
ATWS
H1
070
C1
Y1
071
H3
M1
3.90E-2
1.20E-1
1.30E-2
1.70E-2
1.03E-2
5.07E-5
1.30E-2
4.70E-3
OK
OK
TL2
TL2
TE2
TE2
T-2
T-2
4.5900E-5
1.6655E-6
2.2711E-7
6.2949E-7
8.6750E-7
5.1297E-7
6.5596E-7
2.4133E-7

Figure 3.3 ATWS Event Tree With Main Condenser Available

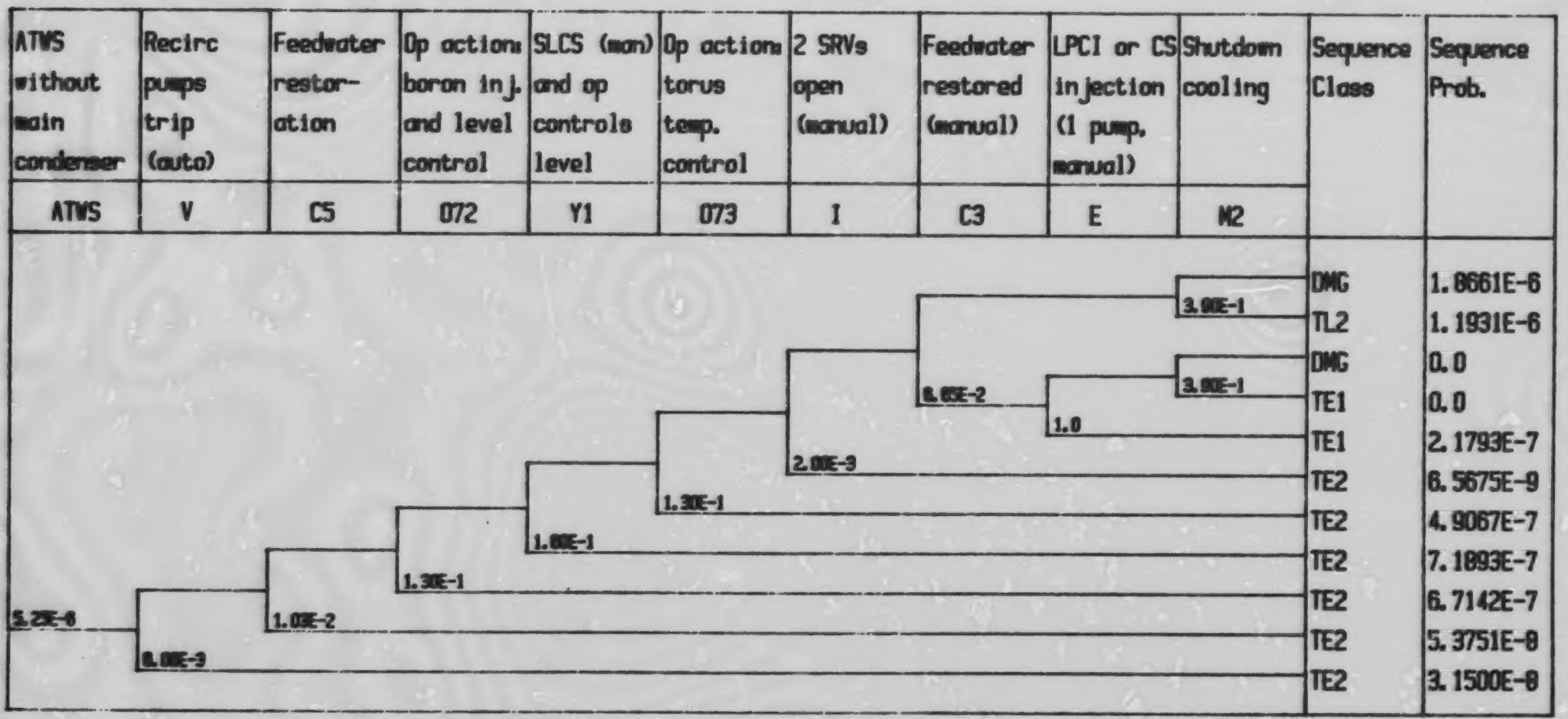
ATWS without main condenser
Recirc pumps trip (auto)
Feedwater restor-ation
Op action: boron inj. and level control
SLCS (man) and op controls level
Op action: torus temp. control
2 SRVs open (manual)
Feedwater restored (manual)
LPCI or CS injection (1 pump, manual)
Shutdown cooling
Sequence Class
Sequence Prob.
ATWS
V
C5
072
Y1
073
I
C3
E
M2
5.25E-6
8.00E-3
1.03E-2
1.30E-1
1.60E-1
1.30E-1
2.00E-3
6.65E-2
1.0
3.90E-1
3.90E-1
DMG
TL2
DMG
TE1
TE1
TE2
TE2
TE2
TE2
TE2
TE2
1.8661E-6
1.1931E-6
0.0
0.0
2.1793E-7
6.5675E-9
4.9067E-7
7.1893E-7
6.7142E-7
5.3751E-8
3.1500E-8

Figure 3.4a ATWS Event Tree With Main Condenser Unavailable

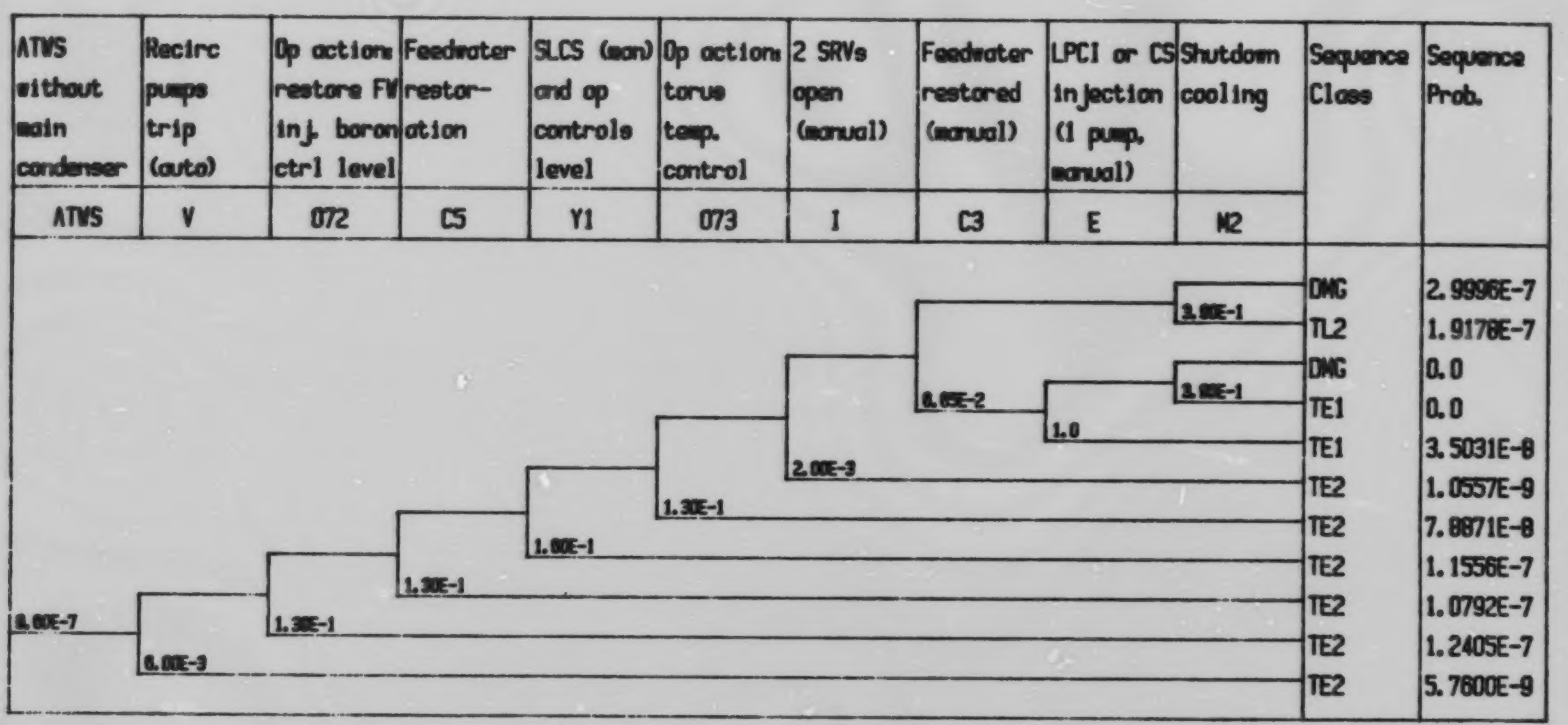
ATWS without main condenser
Recirc pumps trip (auto)
Op action: restore FW inj. boron ctrl level
Feedwater restoration
SLCS (man) and op controls level
Op action: torus temp. control
2 SRVs open (manual)
Feedwater restored (manual)
LPCI or CS injection (1 pump, manual)
Shutdown cooling
Sequence Class
Sequence Prob.
ATWS
V
072
C5
Y1
073
I
C3
E
M2
9.60E-7
6.00E-3
1.30E-1
1.30E-1
1.60E-1
1.30E-1
2.00E-3
6.65E-2
1.0
3.90E-1
3.90E-1
DMG
TL2
DMG
TE1
TE1
TE2
TE2
TE2
TE2
TE2
TE2
2.9996E-7
1.9178E-7
0.0
0.0
3.5031E-8
1.0557E-9
7.8871E-8
1.1556E-7
1.0792E-7
1.2405E-7
5.7600E-9

Figure 3.4b ATWS Event Tree With Main Condenser Unavailable (Loss of Feedwater)

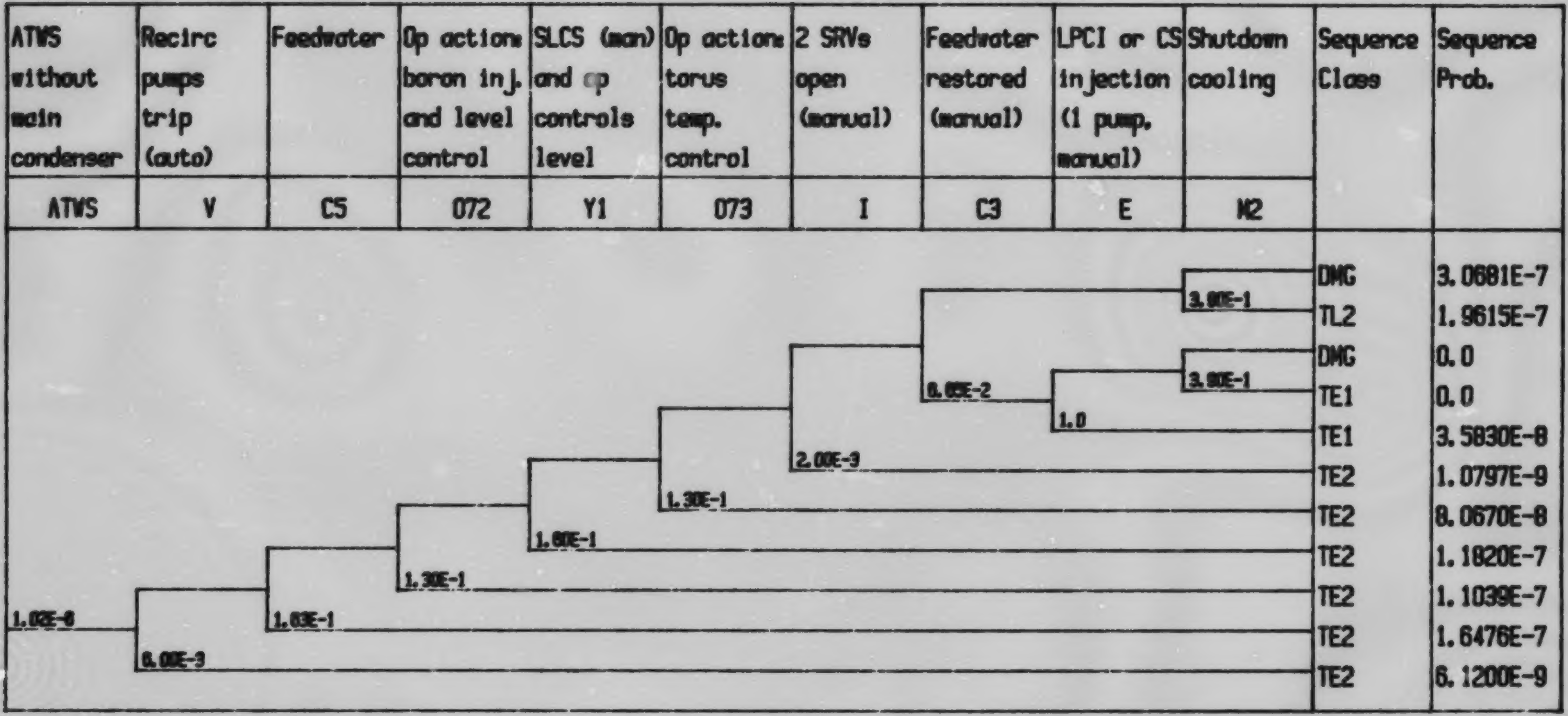
ATWS without main condenser
Recirc pumps trip (auto)
Feedwater
Op action: boron inj. and level control
SLCS (man) and op controls level
Op action: torus temp. control
2 SRVs open (manual)
Feedwater restored (manual)
LPCI or CS injection (1 pump, manual)
Shutdown cooling
Sequence Class
Sequence Prob.
ATWS
V
C5
072
Y1
073
I
C3
E
N2
1.02E-6
6.00E-3
1.83E-1
1.30E-1
1.80E-1
1.30E-1
2.00E-3
6.65E-2
1.0
3.90E-1
3.90E-1
DMG
TL2
DMG
TE1
TE1
TE2
TE2
TE2
TE2
TE2
TE2
3.0681E-7
1.9615E-7
0.0
0.0
3.5830E-8
1.0797E-9
8.0670E-8
1.1820E-7
1.1039E-7
1.6476E-7
6.1200E-9

Figure 3.4c ATWS Event Tree With Main Condenser Unavailable (Loss of Normal Power)

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overly conservative. Event M2 success has been redefined as requiring only SDC, which reduces the failure probability from 0.49 to 0.39. It is worth noting that this change does not mean that torus cooling can be used in the Alternate SDC mode as a backup to SDC. The use of Alternate SDC (or any other torus recirculation system) is precluded during ATWS events because they would dilute the boron concentration and return the reactor to criticality.

- For the loss of feedwater (LOF) ATWS, recovery was improperly applied directly to the initiator frequency. It should have been applied after the cognitive decision of the operator to respond to the ATWS event. The ATWS tree has been modified specifically for this case so that the cognitive decision (072) appears before the feedwater system event (C5). Event C5 has been redefined for this case as feedwater restoration. Credit for restoration of feedwater is applied only when the cognitive decision is successful. The failure probabilities for these events are taken directly from the PSS.

The ATWS requantification is shown on Figures 3.3 and 3.4, with the values for each event and sequence presented on the trees. Figure 3.3 is for non-isolation (PCS available) transients. Figure 3.4 is for condenser isolation (loss of PCS) transients (3.4a is loss of PCS alone, 3.4b is for loss of feedwater including a calculation for loss of service water and loss of TBSCCW, and 3.4c is for loss of normal power).

The requantification of ATWS case 2 assumed that the 43 gpm SLCS could not mitigate an ATWS isolation transient. This calculation is very straightforward, since the assumption means that all ATWS with the main condenser isolation transients lead directly to core melt. Thus, the major contribution to core melt frequency is equal to the total frequency of all transients where the main condenser is unavailable times the RPS failure probability. This includes isolation transients in which the main condenser is initially available but subsequently is isolated (sequences 7 and 8 on Figure 3.3). The core-melt frequencies shown on the non-isolation tree (Figure 3.3) obviously remain unchanged.

The overall results of the requantification of ATWS for both cases are shown in Table 3.3. The results are presented in terms of the plant damage state. For both cases, the requantified values for total ATWS core melt are smaller than the ISAP study values by a factor of about 2 to 3. This is because the overly conservative ISAP RPS failure probability more than compensates for the other areas which are generally non-conservative. An interesting result is that the two cases presented are only about 15% apart in total ATWS related core melt frequency. That is, taking credit for the 43 gpm SLCS only reduces ATWS related core melt frequency by 15%. The only significant effect is at the plant damage state level, where the "no credit" case results in a much higher percentage of ATWS related early melts. The difference in the frequency total core melt (ATWS and non-ATWS) between these two cases is negligible.

Table 3.3 REQUANTIFICATION OF MILLSTONE 1 ATWS EVENT TREES

Plant Damage State	Frequency Per Year Case 1 - Credit for 43 gpm SLCS	Case 2 - No Credit for 43 gpm SLCS
TE2	4.1E-6	8.4E-6
TE1	2.9E-7	---
TL2	2.6E-6	9.0E-7
TOTAL	7.0E-6	9.3E-6

(Note: No credit for 43 gpm SLCS is for isolation transients only. Credit is always allowed for non-isolation transients.)

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4.0 REVIEW OF THE MILLSTONE UNIT 1 ISAP TOPICS

In this section the ISAP topics analyzed by the licensee using PRA techniques will be reviewed. As was mentioned previously, only a portion of all the ISAP topics for the Millstone Unit 1 are analyzed by the licensee using PRA techniques. This report is only concerned with the review of this portion of the topics.

The licensee used three methods for evaluating the impact of resolution of each topic on public risk. In Method A, the change in core-melt frequency and public risk (measured in man-rem) as a result of the resolution of a topic was evaluated. For those topics where direct quantification of change in core-melt frequency or man-rem exposure was not possible, engineering judgment was used for ranking of the topic. This method is referred to as Method B. Finally, for those topics where the impact on public risk is non-radiological, Method C, consisting of calculation of public risk in terms of early and latent fatalities and conversion of these numbers to equivalent total person-rem exposure was used.

Following the calculation of the change in public risk (measured in man-rem) as a result of modification due to each topic, the importance of each topic was scored by the utility on a scale of -10 to +10. The scale used is linear with each unit corresponding to an expected exposure of 400 man-rem. A zero score implies no change in public risk. A negative score implies an increase in public risk and a positive score implies a decrease in public risk. Thus, a decrease in public risk of 4000 man-rem or more as a result of a modification due to an ISAP topic is given the maximum scale of +10. Alternatively, an increase in public risk of 4000 man-rem or more that might occur as a result of a change due to an ISAP topic is given the maximum negative scale of -10.

In evaluating the public risk impacts of those ISAP topics which were analyzed using Method A, the licensee used a man-rem exposure relationship based on the Millstone Unit 1 PSS results. Since this relationship is important in prioritization of the topics, some comments on the validity of the assumptions used in this relationship will be provided in Section 4.1.

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In order to rank the importance of the topics reviewed in this report, a review of the different methods that are appropriate for this purpose was performed. The results of this review, along with a recommended scheme for ranking the importance of ISAP topics, are presented in Section 4.2. This is followed by the results of the review of individual topics.

4.1 Comments on the Utility's Method of Public Risk Quantification

Public safety impacts of individual ISAP topics were evaluated using either direct quantification based on the Millstone Unit 1 PSS results, engineering judgment, or quantification of equivalent radiological impacts. Direct quantification of public risk impacts was performed using the following equation:

$$\Delta R = TK \sum_i \Delta P_i \times M_i$$

where

ΔR = total change in public risk, man-rem
T = remaining plant life (25 years)
K = 3×10^6 man-rem/core-melt
ΔP_i = change in frequency of plant damage state i
M_i = a multiplier that depends on the performance of the containment and consequence mitigating systems

The constant K coupled with the multiplier M_i is a measure of the accident radiological release and public health impact. M_i values of either 0.5, 1.0 or 1.5 were assumed depending principally on containment failure mode and timing.

The K value of 3×10^6 man-rem/core-melt was based on consideration and adjustment of information in the Sandia Siting Study (9) and the Millstone Unit 3 PSS (10). However, the actual population exposure that would result from a core-melt at Millstone Unit 1 is highly uncertain and would depend strongly on containment failure mode and timing. For example, man-rem values calculated in the Sandia Siting Study and reported in NUREG/CR-2723 (11) for hypothetical core-melt releases at Millstone 1 vary broadly as indicated below.

Accident	Release Fractions for I, Cs, Te	Man-rem*
SST1	0.5 - 0.6	$3x10^7$
SST2	$3x10^{-3}$ - $3x10^{-2}$	$2x10^6$
SST3	10^{-5} - $2x10^{-4}$	$7x10^3$

The release fractions assumed for SST1, 2 and 3 were based on WASH-1400 vintage source term methodology and therefore are likely to be somewhat conservative.

The limited containment analysis performed for Millstone Unit 1 as part of the IREP study concluded that the most likely core-melt releases corresponded to release categories BWR3 and BWR4 from WASH-1400. These categories had release fractions for I, Cs and Te of 0.1-0.3 for BWR3 and $8x10^{-4}$ - $5x10^{-3}$ for BWR4. Again, these are likely to be somewhat conservative.

Based on the information above, and our awareness of the large uncertainties involved, we feel that a "representative" estimate of $3x10^6$ man-rem/core melt is reasonable. However, given the extreme variability (orders of magnitude) due to aspects of containment performance, the assumption of only a limited range of M_i values (all close to 1) seems unjustified. Either a broader and more representative range should be used, or the factor should be dropped altogether. Developing a more representative range would require that at least a limited containment analysis be performed. However, having that analysis would allow increased confidence in translating core-melt frequency changes into changes in public health risk.

4.2 REVIEW OF DIFFERENT METHODS FOR RANKING THE IMPORTANCE OF ISAP TOPICS

One of the most attractive features of using Probabilistic Risk Assessment (PRA) techniques for the analysis of an issue is that this technique allows the analysts to generate numerical values for the importance of the issue. This numerical value could, for example, be the effect of resolution of the issue on the core-melt frequency or total population exposure or the overall risk (public health and economic) associated with the operation of the plant. This is an important advantage for using the PRA techniques despite the commonly known uncertainties associated with the numerical results. Currently there are a number of different importance measures that are used in PRA analyses. The objective of this section is to present an overview of the major methods currently used for ranking the importance of an issue and discuss the advantages and disadvantages of each method. This is followed by a recommended method that would be best suited for ranking of the ISAP topics.

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*Total man-rem over all distances (not limited to 50 miles).

4.2.1 Change in Core Melt Frequency

A simple and relatively straightforward method for assessing the importance of an issue is to evaluate the effect of resolution of the issue on the core-melt frequency of the plant. The issues could be ranked in terms of either a numerical scale or any other scheme such as high, medium and low.

The change in core-melt frequency along with a high, medium or low ranking was used in the assessment of the importance of the issues that were analyzed as a part of the Systematic Evaluation Program (SEP). The following approximate guidelines were used for ranking of each individual issue. If the change in core-melt frequency as a result of resolution of an issue was above approximately 10% of the plant's total core-melt frequency, the issue was ranked as high. If the change in core-melt frequency was between 1% and 10% of the plant's total core-melt frequency, the issue was ranked as medium. Those issues that their resolution resulted in less than 1% of the plant's total core-melt frequency were ranked as low in importance.

These guidelines on ranking of the issues were further supplemented by suggestion on how to treat issues falling into each category with respect to implementation of the recommended modifications.

The major advantages of using the change in core-melt frequency as a measure of importance of an issue include:

1. Calculation of change in core-melt frequency as a result of the resolution of an issue is relatively straightforward.

2. The level of uncertainty associated with core-melt frequency estimates is lower than those associated with more sophisticated measures of importance, such as public risk, that require estimates of accident source term and containment failure probability.

3. There is an inherent measure of economic protection (plant investment) along with public health and safety protection built into this measure. This point will be discussed in more detail in later sections.

The major disadvantage of this measure is that core-melt frequency does not necessarily correlate with public health risk. This is due to the fact that effects of containment as a fission product retention mechanism and consequence factors such as site population, meteorology or evacuation are not included in this measure. Lack of consideration of containment performance would be very important in the case of nuclear power plants with substantial capability for scrubbing and retention of fission products following a large scale core-melt accident. Also, characteristics of the specific site could have a large influence on the overall risk associated with a large scale core-melt accident.

4.2.2 Change in Risk as Measured by the Total Population Exposure (Man-Rem)

The second method for assessment of the importance of an issue is to evaluate the effect of resolution of the issue on public risk, as measured for example by total population exposure (man-rem). To calculate the total exposure received by the general population surrounding a nuclear power plant as a result of a core-melt accident, a containment failure analysis, source term analysis, and site consequence analysis must be performed for the plant under consideration.

The obvious advantage of this method is that it includes the plant's containment and site characteristics. Thus, it represents a better measure of public risk. The disadvantage of this method is that additional effort in plant-specific containment and site consequence analysis is required before the effect of resolution of each issue on the total population exposure can be calculated.

One way to reduce this level of effort is to perform a simple containment and site consequence analysis using other studies on similar plants. For example, if there are existing containment failure analyses on similar plants with fairly similar containment designs, this information could be used to develop representative containment failure mode probabilities and source terms for the plant under study. This could be done by taking the release categories developed for the reference plant, adjusting these release categories based on any differences between the reference plant and the plant under study, and subjectively assigning each of the dominant accident sequences developed for the plant under study to the appropriate release categories. In this way a surrogate set of release category source terms and probabilities could be developed.

For the site consequence analysis, the results of Sandia National Laboratories Siting Study (9) or other similar studies, could be used. In Sandia's Siting Study, consequences associated with several hypothetical core-melt accidents at each nuclear power plant in the United States were evaluated. The source terms used for this study were based on a generic set developed by the NRC and referred to as the Siting Source Terms (SSTs) (12). For the consequence analyses, meteorological records from 29 National Weather Service stations were used to represent site, meteorology for plants around the country. This was supplemented by the use of actual site wind rose data. Site-specific population data and a generic evaluation model were used in this study. The end result of the study was a substantial amount of information such as total population exposure (man-rem), early and latent fatalities and early and latent injuries for each SST and each plant site in the United States.

Once surrogate release category source terms for the plant under study are developed using detailed studies on similar plants, the results of the Siting Study could be used to crudely estimate the consequences of each core-melt sequence in terms of population exposure (man-rem) or early and latent injuries and fatalities.

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As was mentioned earlier, the consequence analyses performed in the Siting Study were based on generic release categories SST 1 through 3. Those results must be modified based on the surrogate source terms developed earlier. This could be done by first collapsing the surrogate release categories so that they correspond at least roughly, to SST 1 through 3. Then scaling factors for each release category in relation to the SSTs could be found. Using these scaling factors, the results found by the Siting Study for the plant under consideration could be modified to estimate the consequences associated with each core-melt sequence.

It is important to note that although this method is very approximate, it could provide results that might not be substantially different than those found based on a more detailed plant-specific analysis. This is due to the large uncertainties associated with containment and consequence analyses.

4.2.3 Combination of Core Melt Frequency, Change in Total Population Exposure and Backfit Costs

So far we have discussed the advantages and disadvantages of using either change in core-melt frequency or public health risk (represented by the change in total population exposure) for resolving an outstanding issue. In an attempt to combine the special features of change in core-melt frequency, change in total population exposure, and cost associated with any proposed modifications, a ranking scheme has been proposed in NUREG-0993 which is reproduced as Figure 4.1 (13). The basic reasoning behind assigning a high, medium or low importance to an issue is as follows.

The resolution of an issue is always ranked high if one of the following exists:

a. The expected benefit in terms of reduction in total population exposure over the life of the plant is 1000 man-rem or more.

b. The change in core-melt frequency of the plant is 10^{-5}/reactor-year or more.

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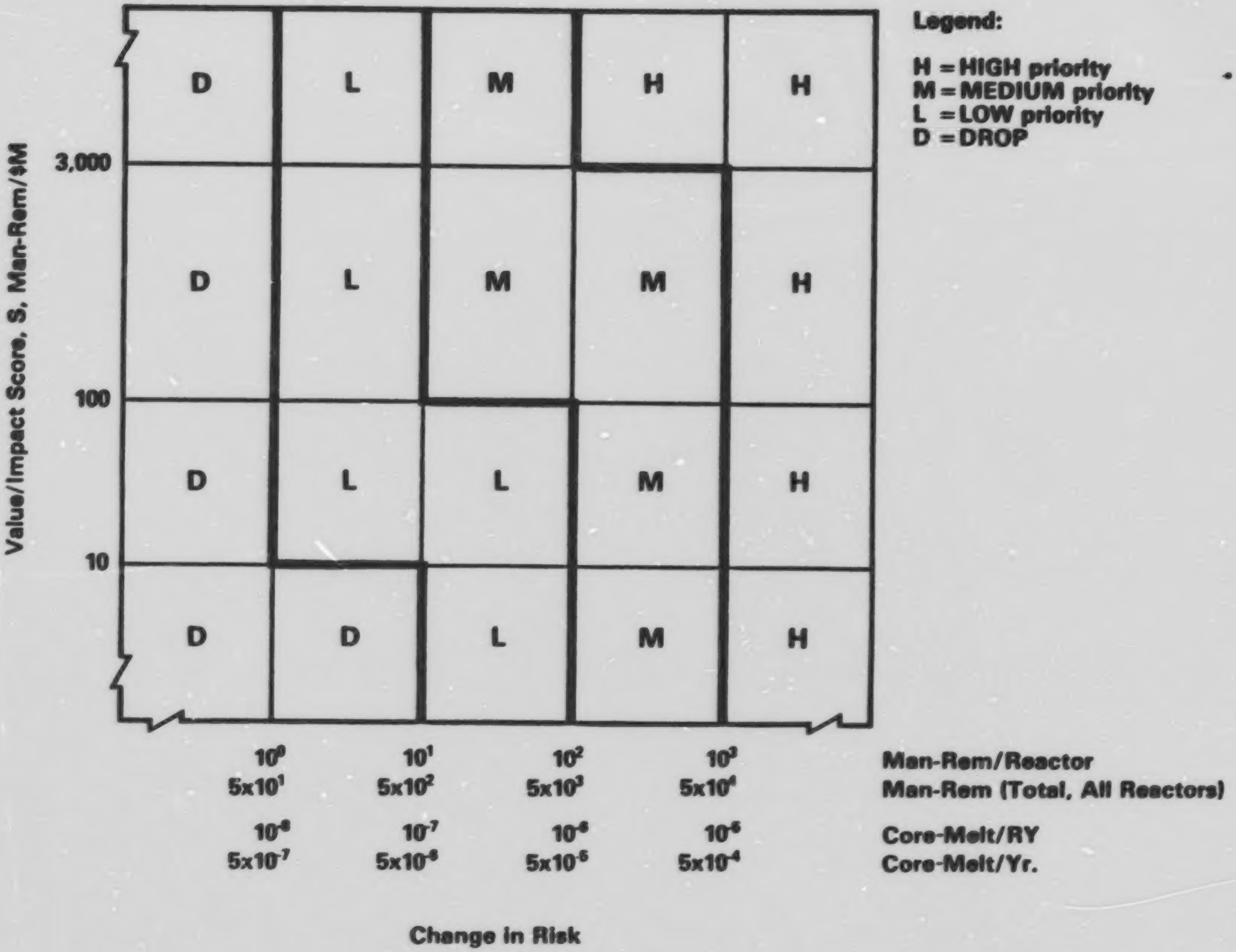

D	L	M	H	H
D	L	M	M	H
D	L	L	M	H
D	D	L	M	H

Figure 4.1 Ranking Scheme Proposed in NUREG-0993.

c. The benefit in terms of reduction in total population exposure over the life of all affected reactors is greater than 50,000 man-rem (this is based on 500 man-rem/reactor for 100 reactors).

d. The change in core-melt frequency of all affected plants is greater than $5x10^{-4}$ per year.

The resolution of an issue can be ranked as high even if core-melt frequency and population exposure reductions are lower than the above thresholds if the cost associated with the modification is sufficiently low. For example, as shown in Figure 4.1, if the cost of resolution of an issue is below 3000 man-rem/$$10^6$ (i.e., $333/man-rem), then it would be ranked high if the change in core-melt frequency and population exposure were in the next lower range.

The resolution of an issue is always ranked medium if it is 10 or more percent of the high criteria. The ranking would always be low if it is between one and 10 percent of the high criteria. Finally, an issue would be dropped if its resolution results in benefits that are less than .1% of the high criteria.

Obviously to use this ranking scheme or a similar ranking scheme, it is necessary to have core-melt, containment and consequence analysis results for the plant under study. In addition, an estimate of the cost of performing the proposed modifications for resolution of each issue should be available.

4.2.4 Consideration of all of the Financial Consequences of a Hypothetical Accident

In reviewing the different ranking schemes so far, the major benefits accounted for in resolving a safety issue have been the reduction in core-melt frequency or total population exposure.

In reality a large series of financial benefits are also associated with avoidance of an accident. Some of these fall into the categories of onsite and offsite costs. Offsite costs include costs associated with health effects (both in terms of lost life and injury), property damage, interdiction of crops, decontamination costs, lost wages and relocation expenses of evacuated population (11). Onsite costs consist of items such as capital costs due to loss of the plant, replacement power cost and plant cleanup costs. In general, onsite costs have been shown to dominate offsite costs for most core-melt accidents (11).

If these benefits are included in the cost-benefit analysis of an issue, then a much higher level of expenditure might be justified for resolution of an issue compared to the situation where the criterion is only based on reduction of total man-rem exposure. This issue becomes much more important in those types of accidents such as Three Mile Island where the population exposure as a result of the accident is minimal but the onsite costs due to the total loss of the plant, lack of electrical generation income and cleanup costs are substantial. Thus, minor accidents with respect to public health and safety could have tremendous financial consequences, and therefore higher expenditures are warranted to avoid them than would be indicated by analyses simply addressing population exposure reduction.

In the next section a simple ranking scheme proposed for ranking of the ISAP topics will be discussed.

4.2.5 Proposed Method for Ranking of the ISAP Topics

The brief review of different ranking schemes has shown that each method has certain advantages and disadvantages. Thus, no single method would be completely satisfactory for all cases.

There are several considerations that must be kept in mind when choosing a method for ranking of the ISAP topics. The first is that the method should be simple, straightforward, and not require a substantial amount of effort for ranking of each topic. The variables used for ranking of each topic should be a good measure of probability of occurrence of an accident and release of radioactive material outside the containment, i.e., a good measure of risk associated with the operation of the plant. Even though public health and safety are the primary objectives of the NRC regulations, the ranking method should in an indirect way address the substantial onsite and offsite financial costs associated with a major accident.

With all these factors in mind, a two-step ranking scheme consisting of consideration of change in core-melt frequency and total population exposure is proposed. The first step consists of evaluating the change in core-melt frequency as a result of the resolution of the topic. Change in core-melt frequency is proposed as the primary measure of importance of the issues for several reasons. First, it provides a direct measure of the importance of any proposed hardware or procedural change as a result of resolution of an issue. The only exception would be a change that affects containment or accident mitigation performance. Also, change in core-melt frequency is relatively straightforward and the level of confidence in the final numerical results is higher than numerical results for risk measures that must include containment and consequence analyses. Finally, there is an inherent measure of financial risk associated with core-melt frequency. If the primary measure of importance were the population exposure, then in cases where there is core damage but minor or no release of radioactivity, the importance of the issue would be unjustifiably ranked low.

Table 4.1 shows the proposed ranking based on change in core-melt frequency. As can be seen in this table, the numerical criteria used for ranking of the issues are fixed as opposed to criteria that are based on a percentage of core-melt frequency for the plant under study. This is more rational since it will not penalize those plants with low core-melt frequency and help those plants with high core-melt frequency.

The cutoff core-melt frequency of $5x10^{-5}$ per year for ranking an issue high was chosen based on consideration of the Commission's proposed safety goal core-melt frequency of 10^{-4} per year and our previous experience with the SEP Phase II which had shown that issues resulting in changes in core-melt frequency of about $5x10^{-5}$ per year and higher are important contributors to the dominant core-melt sequences (14). The other cutoff points are one and two orders of magnitude lower than the high cutoff rate.

The second step in this ranking process is to estimate the total population exposure as a result of resolution of the issue. The purpose of this second step is to upgrade the ranking that was done based on change in core-melt frequency so that low frequency events that could lead to large consequences are ranked higher than the ranking used based on the change in core-melt frequency alone. In addition, this second step allows ranking of

Table 4.1 Proposed Ranking Scheme Based on Change in Core-Melt Frequency

Change in Core-Melt Frequency As a Result of the Resolution of An Issue (per year)	Rank
CM $>5\times10^{-5}$	High
$5\times10^{-6}<$ CM $<5\times10^{-5}$	Medium
$5\times10^{-7}<$ CM $<5\times10^{-6}$	Low
CM $<5\times10^{-7}$	Drop

Table 4.2 Proposed Supplemental Ranking Scheme Based on Change in Total Population Exposure

Change in Total Population Exposure as a Result of the Resolution of an Issue (man-rem)	Rank
Total Exposure (E) > 5000	High
500 < E < 5000	Medium
50 < E < 500	Low
E < 50	Drop

those issues that only affect containment performance and would not be ranked in step 1 above. Table 4.2 shows the proposed supplemental ranking scheme using change in total population exposure.

For example, based on the results of the Siting Study, the total population exposure as a result of an SST2 release is in the order of $2x10^6$ man-rem (11). The SST2 corresponds to accidents involving loss of core cooling with containment emergency safety functions available. For this type of release category the 5,000 man-rem criteria approximately corresponds to the $5x10^{-5}$/year core-melt frequency which is the lower end of high ranking based on change in core-melt frequency. The total population exposure for an SST1 release is on the order of $2x10^7$ man-rem (11). The SST1 corresponds to the most severe radioactive release following a core-melt accident. It involves failure of core cooling and containment emergency safety functions with severe breach of containment. For this type of release category the 5,000 man-rem criteria corresponds to the $5x10^{-6}$/year which is the lower end of medium ranking based on change in core-melt frequency.

Thus, for the case where the change in core-melt frequency is on the order of $5x10^{-6}$ and it involves a severe containment failure and radioactive release, the issue would be ranked medium using the change in core-melt frequency criteria. But the total exposure criteria of Table 4.2 will upgrade this ranking to high. This will ensure that low probability events with large consequences are ranked appropriately.

Finally, it should be emphasized that for most plants a simple containment and consequence analysis using existing information and surrogate source terms would be sufficient for developing the total population exposures for this ranking scheme. Thus, there should not be a need for a large effort in performing a sophisticated containment and consequence analysis.

4.3 Topic 1.01: "Gas Turbine Generator Start Logic Modifications"
Topic 1.24: "Emergency Power"

4.3.1 Background

The NRC has a continuing concern over the reliability of emergency power sources. A number of internal studies as well as virtually all PRAs have indicated that loss of offsite power is a major contributor to core melt. The Millstone Unit 1 ISAP study found that 30% of the core melt frequency was due to this initiator, with over one third of that due to failure of the gas turbine generator. The purpose of this combined issue is to evaluate the possible improvement of gas turbine reliability by making modifications in two particular areas: by-passing nonessential protective trips during emergency operation and improving the gas turbine preventive maintenance program.

4.3.2 Utility Evaluation

This issue was evaluated using Method A of the utility's prioritization procedure. For each of the areas mentioned above, a number of modifications were suggested. The effect of the modifications was evaluated by reviewing the operating history of the gas turbine, in particular the failures it has experienced, and determining if the implementation of the modifications would eliminate any future occurrences of previously observed failures. The failure probability of the gas turbine was then recalculated with the "eliminated" failures removed from the data base. The new, lower gas turbine failure rate was then used to requantify the failure rate of the gas turbine AC power train. This resulted in lower split fractions for support states involving loss of this train. The event tree sequences were then requantified using the new split fractions.

The analysis was broken down into four parts, the implementation of which would have the following descriptions and effects. The first involved by-passing the only two nonessential start trips not already by-passed (gas turbine light-off speed and generator excitation speed). Two previous failures were attributed to these trips. The analysis stated that since the trips would not be by-passed under normal conditions, they would not be totally eliminated. It was assumed that only one of the failures would be

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eliminated by this modification. The second part involved by-passing the only nonessential operating trip not already by-passed (high lube oil temperature). It was subsequently determined that it was in actuality by-passed, thus further analysis was not required. The third part regarded improvements in the preventive maintenance program not already in place. Only improved governor maintenance was identified as having potential to eliminate failures, and three were identified. The fourth part proposes to by-pass five nonessential generator trips (loss of excitation, opening of the exciter breaker, negative sequence, reverse power, and generator under-speed). No failures due to these trips have occurred in the operating history of the unit, but for the purposes of the analysis it was assumed as a bounding value that one failure would be eliminated. Thus, the total number of trips eliminated was five. This resulted in a reduction in core melt frequency of about 1E-5, essentially all of which was in plant damage states TE1 and TI1. The sum total reduction in risk from all the suggested modifications was 375 man-rem over the life of the plant, or a prioritization score of 1 out of 10.

4.3.3 Review of the Utility Evaluation

The analysis performed for this issue is straightforward and methodologically sound. That is, we concur with the elimination of past failures from the data base to account for a modification of the system/procedures and a recalculation of core melt frequencies based on the reduced number of failures. Thus, our review of this issue need only deal with two specific areas. First, are the suggested modifications reasonable and inclusive? Second, was the determination of the number and type of "eliminated" failures also reasonable? This was done by reviewing in detail the historical data on Millstone 1 gas turbine failures (15).

Treating the review by parts, as the analysis was performed, we have a few mostly minor comments. For the first part, there is no statistical basis for the argument which only eliminated one of the two failures. If the trips had been by-passed the failures would not have occurred during a real emergency demand, and thus both failures should have been eliminated. We agree that there are no other failures which would be eliminated by by-passing these trips. The third part (the second part being moot) has properly identified three governor failures as being preventable with improved maintenance. Our review of the seven governor-related failures concurred with this finding. However, we identified two additional failures which we feel could have been prevented by improved maintenance procedures. These are (1) a failure due to oxidation on the wiper arm of a variable potentiometer, and (2) a failure caused by oil impregnating a speed signal cable which resulted in a loss of speed signal. Better visual inspection and/or cleaning of these areas during maintenance could eliminate further occurrences of these failures. This increases the number of failures eliminated by this part of the issue to five. For the fourth part, our review concurs with the analysis that no failures have occurred due to the trips to be by-passed. It is debatable whether the assumption of one additional failure eliminated is reasonable in light of the existence of actual failures for the other parts of the analysis. The absence of failures due to these trips could be said to indicate that this part of the proposed modifications has little benefit compared to the other parts. Thus, we lean towards not crediting any further elimination of failures due to this part of the modifications. This leaves us with a total elimination of seven failures from modifications in the first and third parts of the analysis as opposed to the utility result of five failures from the first, third, and fourth parts. This would result in a total core melt reduction in plant damage states TE1 and TI1 of about 1.4E-5.

4.3.4 Conclusions

Our estimate of reduction in core melt frequency from the resolution of this topic is 1.4E-5/year, 40% higher than the utility estimate. Further, we disagree in how this reduction is obtained. The modification to by-pass two nonessential start trips should remain an integral part of the total modification package, as should improvements in preventive maintenance of the governor. However, additional improvements to the preventive maintenance program to better inspect and clean key electrical and mechanical components to detect insipient failures due to fluid leakage and corrosion/oxidation should be added. Further, we disagree as to the need to include the by-pass of nonessential generator trips in the modification package since there has been no solid evidence that failures could be averted by this modification.

Overall, we rank this topic, based on our proposed ranking scheme as medium in safety significance.

4.4 Topic 1.02: "Tornado Missile Protection"

4.4.1 Background

The potential for damage to important plant systems caused by tornado generated missiles was addressed during the NRC's Systematic Evaluation Program (SEP). A potential weakness was found in the Millstone Unit 1 plant because of the lack of tornado hardening of several important safety-related systems. The SEP assessment found that the fire water tank and the condensate storage tank were both susceptible to damage from tornado missiles. The damage would result in a loss of the water supplies to the isolation condenser. Additionally, the switchgear rooms in the turbine building were also found to be susceptible to tornado missile damage. The power cables from both the gas turbine generator and the diesel generator are located in this area. During a tornado a loss of offsite power is probable and damage to the switchgear room could result in the loss of emergency power to the power conversion system (PCS) shutdown cooling system and alternate shutdown cooling system. Therefore, it is possible that a tornado of sufficient magnitude could initiate a plant transient and defeat all four decay heat removal systems, i.e., IC, PCS, SDC and Alternate SDC system.

4.4.2 Utility Evaluation

Northeast Utilities proposes using city water and a portable pump to provide a secondary source of makeup water to the isolation condenser. In their analysis, the utility has assumed that the probability of a tornado striking the Millstone site, the town water supply and pumping station is relatively small, especially compared to the utility's estimated probability of the failure to make the manual connection between the city water supply and the makeup to the isolation condenser. The utility sees this alternate source of isolation condenser makeup as being useful during all station blackout situations and has calculated the benefit associated with the improved reliability of the makeup system for all blackout situations.

Based on the tornado missile risk analysis performed for Millstone Unit 3, the frequency of a tornado of sufficient magnitude to damage the water storage tanks striking the Millstone site is 1.0E-5/yr. (The required wind speed used was 165 mph. This was based on the analysis performed for Connecticut Yankee as part of the SEP Tornado Missile Topic.) In the analysis for Millstone Unit 1, Northeast Utilities has assumed that if a tornado of this magnitude does strike the site, the condensate and fire water tanks will be struck by a tornado missile, as will the switchgear room and the tornado will cause a loss of offsite power. These assumptions result in a core melt frequency, from tornado initiated events, of 1E-5/yr.

The use of city water to supply makeup to the isolation condenser provides an alternate source of water to remove decay heat under these conditions. The utility has assigned a 0.2 failure probability for the failure of the use of city water as makeup to the isolation condenser. Half of this value is due to an assumed failure of the town water supply; the remainder is due to pump failures and operator errors (failure to start the pump or connect the water supply). This alternate source of isolation condenser makeup reduces the core melt frequency from tornado-induced transients by nearly 8E-6/yr. Using the utility supplied consequence model, this results in a 300 man-rem exposure reduction over the remaining plant lifetime.

Northeast Utilities sees more benefit from this modification for other (non-tornado-induced) loss of normal power events that result in station blackout. During a station blackout, the loss of the fire water system and consequently the isolation condenser makeup system results in a core melt since the blackout disables the other three decay heat removal systems. The core melt frequency from a station blackout with the failure of the fire water system as calculated from data in the Millstone Unit 1 PSS is 4.1E-5/yr. The addition of the redundant makeup supply from city water reduces this frequency by a factor of 0.2 to 8.2E-6/yr. This reduction of 3.3E-5/yr corresponds to a 1230 man-rem reduction in exposure to the public when using the utility's consequence model.

4.4.3 Review of the Utility Evaluation

The utility has used information from two other studies to evaluate the importance of tornado initiated events that result in a core melt. An analysis performed for Connecticut Yankee provided the information used to calculate the required wind speed (165 mph) necessary to generate missiles capable of penetrating the water tanks. It seems reasonable to assume that the water storage tanks at Millstone Unit 1 and Connecticut Yankee would be similar enough in design to warrant using the same wind speed value in the simplified analysis performed for this issue. Given this required wind speed, the frequency of the tornados of this size corresponds to values used in other studies for the Connecticut area (16). However, the assumption that once a tornado has struck the Millstone site the water tanks will be damaged seems to be overly conservative. Several studies have shown that the frequency of a tornado missile striking a plant structure is one to two orders of magnitude lower than the frequency of a tornado hitting the site.

Although the utility has calculated the probability of a failure to supply city water to the makeup side of the isolation condenser, the values used for some failures appear to be estimates with large uncertainty bounds. (This applies primarily to the unavailability of city water which was estimated to be 0.1.) Under normal conditions this would appear to be a conservative (high) estimate and the arguments used by the utility to justify independence of the city water supply and the Millstone site in the event of a tornado appear to be reasonable. A bounding analysis, assuming the city water supply is always available, would use a value of approximately 0.1 for the probability of the failure to connect the city water to the isolation condenser makeup. Modifying the loss of normal power events (followed by station blackout and fire water system failures) by this value would result in a change in the core melt frequency of:

$$4.1E\text{-}5/yr - (4.1E\text{-}5/yr)(0.1) = 3.7E\text{-}5/yr$$

This value is only approximately 10% greater than that calculated by the utility and results in a reduction in the exposure to the public of approximately 1400 man-rem (using the utility's consequence model).

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4.4.4 Conclusions

The core melt frequency attributed to tornado-initiated events by the utility appears to be conservative by at least an order of magnitude. This is due to the assumption used by the utility that if a tornado strikes the site, it will generate missiles that will do the required damage. The benefit from the proposed modification for loss of normal power events also appears to be slightly conservative but not significantly different from the maximum achievable reduction from a redundant isolation condenser makeup supply. Using the utilities consequence model, the benefit from the proposed modification appears to be approximately a 1200 to 1400 man-rem reduction over the life of the plant. This reduction is due almost entirely to the reduction in the frequency of loss of normal power induced station blackout core melts, not tornado induced events.

This issue and the following issue, Topic 1.16.1, are very closely related. Both issues deal with improving the ability of Millstone Unit 1 to withstand a station blackout. The proposed modification in this tornado issue addresses the improvement of the reliability of the IC makeup system during a station blackout. This is a subset of the issues addressed in Topic 1.16.1 "Millstone Unit 1/Unit 2 Backfeed." The modifications proposed in Topic 1.16.1 should improve the IC Makeup System reliability as much as the city water connection proposed in this issue.

If the backfeed modification is completed, the reduction in the core-melt frequency due to the subsequent installation of a city water connection is only approximately 3E-6/yr not 3.3E-5/yr as calculated in the earlier analysis. Based on this core-melt frequency reduction and our proposed ranking scheme we rank this issue as low in safety significance.

4.5 Topic 1.04: "RWCU System Pressure Interlock

4.5.1. Background

The Reactor Water Cleanup System (RWCS) at Millstone 1 is used to remove impurities from reactor coolant during all modes of operation. It interfaces directly with the RCS, but parts of the system are designed to operate at pressures much lower than normal RCS operating pressure.

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Pressure in these parts of the system is regulated by an air operated control valve which is backed up by a pair of isolation valves which are designed to close if the regulating valve fails to perform its function. Should these valves fail to isolate under these conditions, reactor coolant will be lost through the system (i.e., a LOCA condition will exist). A single pressure interlock controls both of these valves, which is contrary to the single failure criterion even though a temperature interlock also exists. The purpose of this issue is to evaluate the possible reduction in risk associated with putting in a second pressure interlock.

4.5.2 Utility Evaluation

This issue was evaluated using method A of the utility's prioritization procedure. Two possible events were analyzed. The RWCU system has a relief valve back to the torus in addition to the features previously discussed. If the regulating valve fails and the isolation valves fail to close, a LOCA will occur. If in turn this relief valve opens, flow will be directed to the torus, and this event will be like a standard small LOCA. If the relief valve does not open or is in some way bypassed, an interfacing systems LOCA will occur, resulting in a core melt due to loss of reactor coolant outside of the containment. The frequency of these two events was determined using fault trees to represent the ways in which they could occur. Two cases were considered, one pressure interlock (as is) and two pressure interlocks (modified system). It is also worth noting that the isolation valves will also receive a closing signal from the reactor protection system on low water level, but the utility did not take credit for this signal. The utility notes that this is a conservative assumption.

The frequencies calculated for the two initiators discussed above were used to requantify the frequency of interfacing LOCA and small LOCA core melt for the two cases and the difference between them. In the case of the interfacing systems LOCA, the frequency prior to the "fix" (i.e., the one pressure interlock case) was considered so small (3E-9/yr) that further analysis was not required. For the small LOCA case, the installation of a second interlock resulted in a core melt reduction of about 3E-8. This difference yielded a potential risk reduction of a 4 man-rem over the life of the plant, or a prioritization score of zero on the utility's scale of 10.

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4.5.3 Review of the Utility Evaluation

The major problem with is the utility's evaluation is not taking credit for the isolation signal to the valves from the RPS on low reactor water level. We agree that the assumption is conservative, but since we are prioritizing issues relative to each other, excess conservatism can lead to improper prioritization. In this case, it is obvious that no core damage can occur prior to passing the low level setpoint. Thus, the low level signal should be considered.

The analysis was redone, concentrating specifically on the probability of failing to isolate the piping following failure of the pressure regulating valve. Detailed information on the configuration of the low water level signal was not available, but it was assumed that it was part of the one-out-of-two-twice logic common in the RPS. A simplified diagram of our concept of the overall RWCU isolation system is shown in Figure 4.2. A fault tree analysis was performed for this system failing to isolate. The areas labeled "logic specific to valve X" were ignored in the analysis. It was assumed that the failure of each valve to close mechanically was dominant over the failure of its associated dedicated logic. The fault tree for this system is shown in Figure 4.3. The tree was quantified using data from the utility analysis (valve unavailability = 0.006, switch unavailability = 0.003. The switch unavailability is probably conservative with respect to the level switches, since they are probably tested more frequently than the interlocks, but they will serve for this analysis.

The Boolean equation for the fault tree is:

RWCU System Fails to isolate = VA*VB + P*T*[(LA2*LB1) + (LA2*LB2)]

Substituting the unavailabilities into the equations, the resulting failure probability is:

P(RWCI System Fails to isolate) = 4E-5 + 2E-10 = 4E-5

where the first term is due to mechanical failure of the valves and the second term is due to failure of the isolation signal. As can be seen, the valve failure totally dominates.

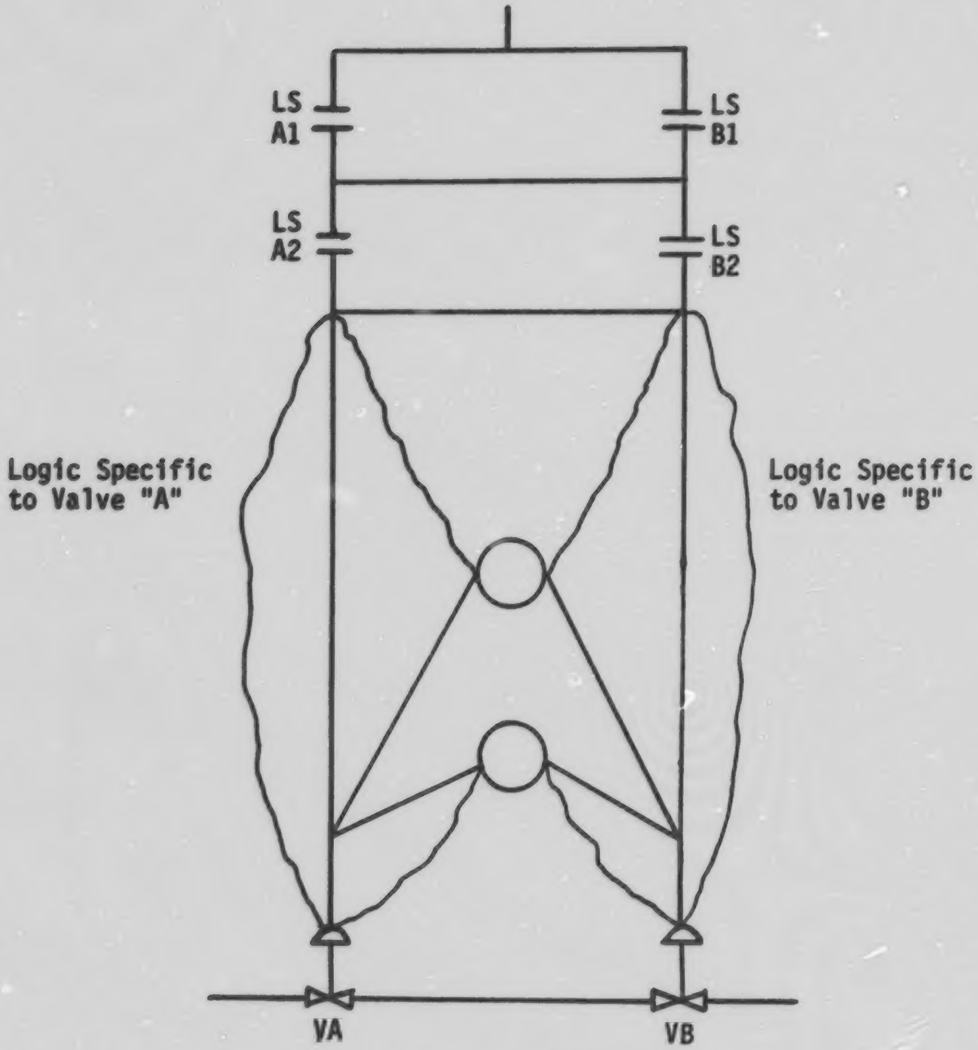
LS
A1
LS
B1
LS
A2
LS
B2
Logic Specific
to Valve "A"
Logic Specific
to Valve "B"
VA
VB

Figure 4.2 Simplified Diagram of the RWCU Isolation System.

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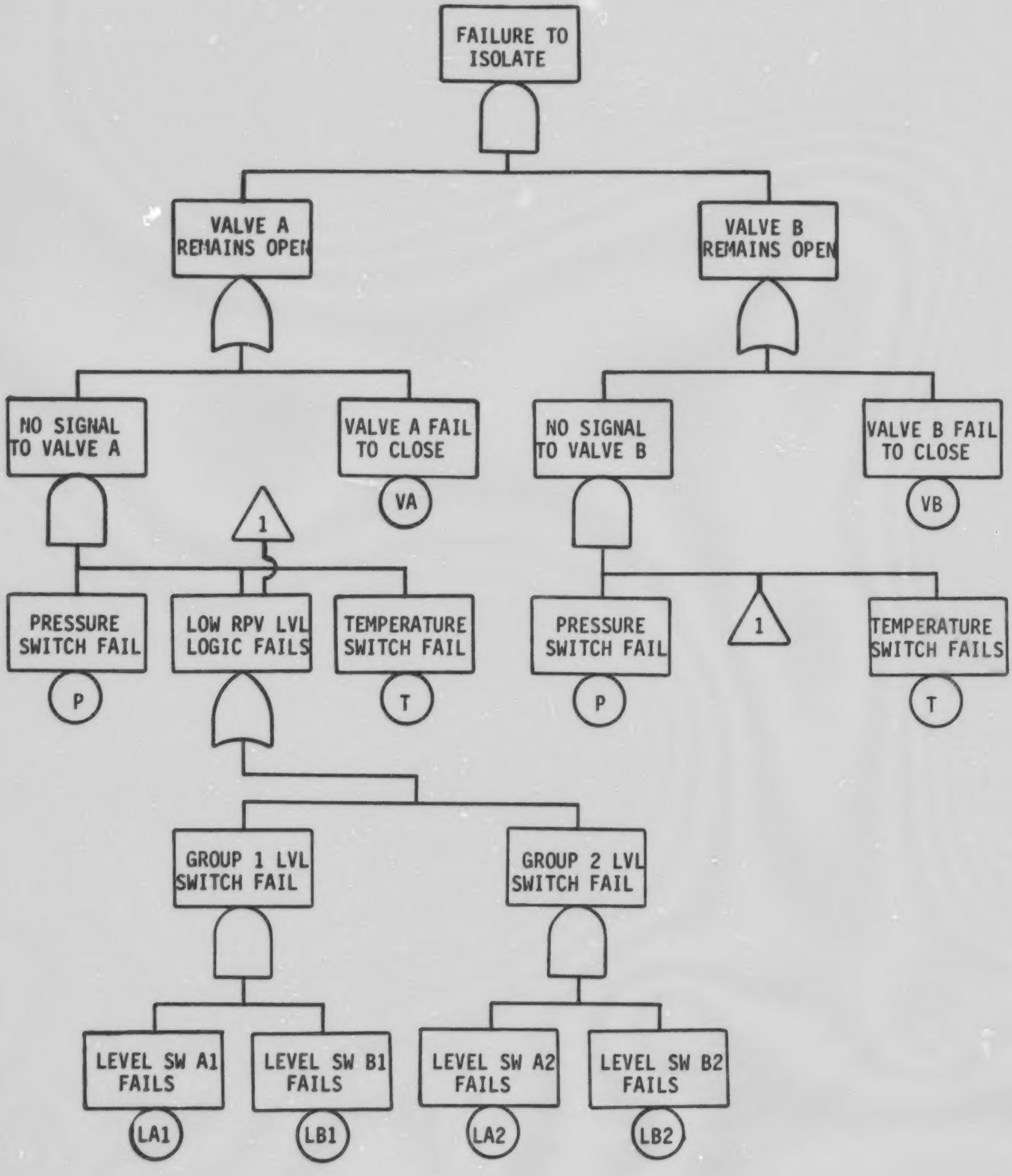
FAILURE TO ISOLATE
VALVE A REMAINS OPEN
VALVE B REMAINS OPEN
NO SIGNAL TO VALVE A
VALVE A FAIL TO CLOSE
VA
NO SIGNAL TO VALVE B
VALVE B FAIL TO CLOSE
VB
1
PRESSURE SWITCH FAIL
P
LOW RPV LVL LOGIC FAILS
TEMPERATURE SWITCH FAIL
T
PRESSURE SWITCH FAIL
P
1
TEMPERATURE SWITCH FAILS
T
GROUP 1 LVL SWITCH FAIL
GROUP 2 LVL SWITCH FAIL
LEVEL SW A1 FAILS
LA1
LEVEL SW B1 FAILS
LB1
LEVEL SW A2 FAILS
LA2
LEVEL SW B2 FAILS
LB2

Figure 4.3 Simplified Fault Tree for Failure of RWCA Isolation System.

There was one other concern in the analysis. It was not completely clear that the temperature in the line would rise sufficiently to actuate the temperature interlock. The utility stated that it would, but this was not explained in detail. If we were to assume that the temperature interlock would not work, the answer would be changed by removing the "T" term from the Boolean equation. The resulting failure probability would then be:

$$P(\text{RWCU System Fails to isolate}) = 4E{-}5 + 5E{-}8 = 4E{-}5$$

and the valve failures would still clearly dominate. Obviously, the addition of a redundant pressure interlock in either case could only reduce the signal failure term of the equation, and thus the overall failure to isolate would remain unchanged.

4.5.4 Conclusions

The addition of a redundant pressure interlock would not alter the probability of a failure to isolate the RWCU line in the case of a failure of the pressure regulating valve. Since this is the case, it can be stated that there could not be any reduction in core melt frequency associated with this modification. Obviously, it is not necessary to evaluate the utility analysis in the area of frequency of the initiator of plant response following the failure to isolate, since these have no bearing on the final answer. We rank this issue as a "drop" by virtue of its having no impact.

4.6 Topic 1.05: "Ventilation System Modification"

4.6.1 Background

Operating electric motors normally require cooling or ventilation to remove heat buildup in the windings which can result is premature motor failure. At Millstone Unit 1, during normal operating conditions, area coolers and fans are being used to provide cooling to electric motors associated with safety related systems, including the Feedwater/F.W.C.I, the Service Water (SW) and the Emergency Service Water (ESW) systems. However, in the present configuration, these cooling equipment will no longer function following a loss of normal power (LNP) event due to their dependency upon normal AC power, and as a result, this may lead to premature failure of the associated systems.

The utility proposes to modify the affected cooling equipment as follows:

- Modify the electrical power sources to the Feedwater/F.W.C.I. area coolers so that all six cooling units will be automatically transferred onto the gas turbine bus following an LNP event.
- Modify the power supplies to the intake structure exhaust fans to allow automatic sequenciing of one fan onto the gas turbine bus, and the other onto the diesel generator bus.

4.6.2 Utility Evaluation

The utility's analysis indicates that a number of safety-related and support systems associated with safety equipment may not function due to inadequate ventilation following an LNP event. These cooling system failures include:

A. Failure of Feedwater/F.W.C.I. due to loss of area coolers following an LNP event

Area cooling for the Feedwater/F.W.C.I. system under normal operating condition requires four cooling units for the two feedwater pumps, and two other units for two sets of condensate and condensate booster pumps. Under LNP conditions, only one feedwater train which consists of one feedwater, one condensate and one condensate booster pump, is required to provide make-up water to the reactor vessel. At present, two of the four area coolers for the feedwater pumps are powered by the gas turbine bus, and thus will automatically restart after LNP. This configuration is considered to be adequate for providing the necessary cooling of the one feedwater pump required following an LNP. However, the cooling units for the condensate and the condensate booster pumps are powered by normal AC bus, and are load-shed during LNP. Without these area coolers, the condensate and the condensate booster pumps will eventually fail due to motor windings overheat, and therefore, will lead to failure of the Feedwater/F.W.C.I. system.

An assessment of the impact on the system availability of the Feedwater/F.W.C.I. caused by the loss of ventilation following an LNP, indicates that the F.W.C.I. system unavailability will change from a value of 1.625×10^{-1} to 1.0(Q=1.0) for certain sequences associated with LNP events. The result indicates a 35% increase in core-melt frequency (CMF) (from 8.06×10^{-4}/yr to 1.09×10^{-3}/yr) due to inadequate ventilation of F.W.C.I. system. This change in CMF contribution appears to be the result of changes in plant damage states TE1 and TI1, and TL2. The calculated public risk associated with this CMF change is aproximately 10,610 man-rems.

B. Failure of SW and ESW systems due to inadequate area cooling in the intake structure

Following an LNP event, two out of the three SW pumps will immediately restart after successful start of both the diesel generator and the gas turbine. However, the intake structure ventilation is load-shed following the LNP event, and thus, will not remove the heat buildup in the structure housing the SW and ESW pumps. While the MCC providing power to the structure exhaust fans is load-shed on LNP, it can be manually restarted since it receives power from an emergency bus.

Given a worse-case scenario with no ventilation in the intake structure and two SW pumps running, the utility's analysis indicates that the potential heat buildup in the intake structure would not affect the performance of the SW pumps. The utility also has performed an analysis for the ESW pumps ventilation which showed that these pumps would not be needed unless feedwater failed, and manual depressurization was required. Under such circumstances, the operator would manually correct power to the exhaust fans before activating the ESW pumps. As a result, it appears that failure of the intake structure ventilation following an LNP would not lead to failure of the SW and ESW systems.

4.6.3 Evaluation of the Utility Analysis

Review of the utility's evaluation of this safety issue indicates that their analysis for Scenario A was adequate. The arguments presented for Scenario B are based on the utility's assessment of heat buildup in the intake structure. We did not review any of the utility's heat load

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calculations. The only concern that might be worth noting is that the heat load was not modeled for the case where both the two SW and four ESW pumps are running at the same time. This scenario should give a worst-case condition for the assessment of the heat buildup in the intake structure following an LNP event. However, this concern should not change the utility's conclusion on this issue, since the exhaust fans can be manually powered through an emergency bus, and ventilation to the intake structure can therefore be restored.

4.6.4 Conclusions

In general, the utility's evaluation of this safety issue is adequate. For Scenario A the increase in core-melt frequency due to loss of ventilation is calculated to be 2.8×10^{-4}/year. Based on our proposed ranking scheme the safety significance of this topic would be ranked high. Scenario B was assessed to have no impact on Millstone Unit core-melt frequency or public risk, and therefore was ranked "drop."

4.7 Topic 1.06: "Seismic Qualification of Safety-Related Piping"

4.7.1 Background

The NRC has been very concerned about the ability of plant structures and equipment to function following an earthquake. I&E Bulletin 79-14 specifically addressed the field verification of the seismic qualification of safety-related piping. Millstone Unit 1 has performed this field verification, and several piping supports were found to be in need of modification. All of the modifications needed to qualify piping for the Operating Basis Earthquake (OBE) have been completed. Many of the modifications needed to qualify piping for the Safe Shutdown Earthquake (SSE) have also been completed. This issue addresses the reduction in public risk if the remaining modifications to qualify piping for the SSE are completed.

4.7.2 Utility Evaluation

This topic was evaluated using Method B of the utility's prioritization procedure. The utility reviewed the results of seismic PRAs for other plants, as well as seismic experience data collected by the Seismic Qualification Utility Group (SQUG) and others. From this information, they concluded that piping generally has higher capacity than other key safety-related structures and equipment and does not contribute highly to core melt risk.

As the basis for their conclusions, the utility specifically points to conclusions by the NRC (17) that equipment of the types usually found in nuclear power plants are not likely to fail at the SSE for plants sited on the East coast. These NRC conclusions also state that strong evidence exists that the emergency systems would function as designed, if required, following an SSE. This is further supported by analyses performed for Millstone Unit 1 during the SEP (18). Additionally, seismic risk estimates from PRAs have been dominated by the failure of large tanks, structures, mechanical and electrical equipment, and buried piping, not the piping addressed by this issue. Using engineering judgment, a prioritization score of 0.1 out of 10 was assigned.

4.7.3 Review of the Utility Evaluation

The utility evaluation is basically judgmental, based on a review of available seismic PRAs and other seismic information. The most comprehensive review of available seismic information presently available is a recent report by the Expert Panel on the Quantification of Seismic Margins (19).

The conclusions of the panel regarding the importance of piping to seismic margins (and risk) are as follows:

> "The Panel believes that, in general, piping systems in nuclear power plants have (minimum) capacities greater than 0.5g pga. However, certain construction details have led to past earthquake damage in industrial facilities. Examples of potential piping failure modes include the following:
>
> - Valve failures caused by impact resulting from large displacements of flexible pipes.

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- Pipe failure caused by large displacement of inadequately anchored equipment (e.g., tanks).

- Failure of small, stiff pipes attached to large, flexible pipes.

- Failure of piping between buildings as a result of large relative displacement caused by rocking or sliding of the buildings.

- Failure of brittle connections, eroded or corroded piping, and brittle cast iron piping.

All these failure modes are related to displacement effects in contrast to inertia-induced stresses."

"Experience from past earthquakes in industrial facilities indicates that piping is rugged and can resist earthquakes of at least 0.5g pga, which is the limit of the experience data. This is also confirmed by recent piping analyses using the methodology developed in the SSMRP.... PRA calculations also support this conclusion. In cases where generic piping fragility values are developed, they are always conservative. Experience also has shown that even if piping supports fail, failure of piping does not necessarily follow. Again, failure of piping is primarily caused by large relative displacements rather than inertial effects."

4.7.4 Conclusions

Based on the work of the Expert Panel, we generally concur with the utility evaluation that the further modification of piping supports (which serve only to increase resistance to inertial failure) is not warranted and is unlikely to have any impact on plant safety. We would temper that judgment with a single restriction, that being that a cursory review of the remaining modifications be performed to determine if any of them were included due to potential displacement failure modes, particularly due to differential motions of buildings, as described in the Panel report. Modifications which would improve ruggedness with regard to these types of failures (if any exist) should be pursued. Excluding identification of any of these special cases, this topic would be ranked as "drop."

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4.8 Topic 1.12 : "Control Room Habitability"

4.8.1 Background

Control room habitability is one of the many areas that can effect the performance of the operators especially during emergency conditions. The areas of concern in this topic include the ability of operators to function during an accident where either radioactivity or chlorine gas has been released. In addition, the control room environment during normal operation should not induce operator errors due to adverse working conditions such as high temperature, high humidity or lack of ventilation.

Due to its potential impact on plant safety, the utility has proposed to upgrade the control room Heating, Ventilating and Air Conditioning (HVAC) system by providing:

- o Air conditioning to the control room using recirculation and outside air make-up during normal operation.
- o Automatic isolation of air intake upon detection of high radiation or chlorine gas.
- o Total recirculation of air by routing air flow through charcoal filters during high radiation or chlorine gas release.

4.8.2 Utility Evaluation

The evaluation performed by the utility for plant safety implications due to deficiencies in control room habitability which could impact the performance of plant operators, was based on the following three scenarios:

A. Control Room Habitability (CRH) during an accident involving a radioactivity release.

In this scenario, it is assumed that a severe accident occurs at Millstone Unit 2 that results in a radioactivity release. At the detection of high airborne radioactivity, the HVAC system automatically isolates the

Unit 1 control room from the contaminated environment, and if needed, the operators may also have to wear a full face mask and use Scotts air-packs. Wearing of protective gas masks may inhibit the operators from performing their tasks properly during such an accident.

In the evaluation of this scenario, the utility uses a bounding analysis involving the following scenarios:

- o Core melt accident at Millstone Unit 2
- o Decision to manually shutdown Unit 1
- o Operators are required to leave the plant
- o Feedwater fails to run after reactor trip
- o Isolation Condenser (IC) or IC makeup fails

The result, as indicated by the utility, is an increase in Unit 1 core melt frequency of 2.5 x 10^{-7}/yr. This corresponds to an equivalent public risk of 10 man-rem.

B. CRH after a release of chlorine gas from railroad tank cars.

As discussed in Topic 2.07 - "Sodium Hypochloride System", a chlorine gas release from the pressurized railroad tank cars may impact the performance of control room operators. A bounding analysis for this scenario is an event that is initiated by a chlorine gas release followed by failure of the feedwater , IC and IC makeup systems. Considering this as worst-case accident, the contribution to core melt frequency is estimated at 9.2 x 10^{-7}/yr given the frequency of chlorine gas release at 1.8 x 10^{-3}/yr. This corresponds to an equivalent public risk of 34.5 man-rem.

C. Potential operator errors due to loss of HVAC system during normal operation.

At Millstone Unit 1, the HVAC system is currently a single train unit. While loss of HVAC has occurred at the Unit 1 control room before, it has not initiated any transient (i.e., transient resulting from the malfuntion of instruments and controls due to high temperature in the control room). However, it is conceivable that a loss of HVAC may induce potential operator errors while performing routine duties, and that could lead to severe consequences. Such potential for human errors may have a significant likelihood when the operator is being exposed to adverse control room conditions such as high temperature, high humidity, and no ventilation.

Although it is apparent that such a risk may occur at Millstone Unit 1, it is not easy to quantify risk that involves stress-related human error. From a qualitative point of view, any improvement in the CRH (such as upgrading the HVAC system) should reduce the chance of the operator committing such errors.

In summary, as estimated by the utility, the proposed upgrading of HVAC system scenarios A and B would result in a core-melt frequency reduction of 1.17×10^{-6} which corresponds to about 45 man-rem in population exposure.

4.8.3 Review of the Utility Evaluation

In general, the analysis performed by the utility for the CRH issue is adequate. However, the evaluation is mostly based on bounding or worst-case assumptions. Our review has produced the following comments.

Scenario A

The analysis for this accident scenario is satisfactory, and the proposed modifications would reduce the risk of core melt in this case. The significant benefit of the proposed changes for this scenario is that it would eliminate the requirment that the operator wear emergency protective masks, and thus reduce the chance of operator errors during such accidents.

Scenario B

As discussed in reviewing Topic 2.07, our estimate of the probability of release of chlorine gas is much lower than the utility's evaluation. Using our estimate for the frequency of premature opening of tank car pressure relief valve of 3.6×10^{-5}/yr instead of 1.8×10^{-3}/yr as indicated by the utility, the resulting contribution to core melt frequency is estimated at 1.8×10^{-8}/yr. This contribution is negligible, and there is no significant impact on the plant safety due to this accident scenario. As a

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result, it is difficult to show that there is any benefit to plant safety in improving CRH for this scenario.

Scenario C

It is acknowledged by the utility that adverse conditions in the control room may effect the performance of operators during normal and emergency operations. However, as indicated by the utility, it is difficult to quantitatively assess the impact on plant safety due to this stress-induced human error issue. It must be noted that ISAP Topic 1.07 which is related to the requirements of NUREG-0737, Supplement 1, requires the utility to perform a Detailed Control Room Design Review (DCRDR) to determine whether or not its present control room conforms to human engineering standards. As part of this initiative, the utility is required to survey the control room for its habitability conditions, and depending on the outcome of this effort, the utility may decide on whether or not the CRH should be improved.

4.8.4 Conclusions

The utility's evaluation of the benefits associated with the control room habitability improvements has shown a reduction in core-melt frequency of 1.17×10^{-6} which corresponds to a public risk reduction of 45 man-rem during accident conditions. Our review showed that the benefits only come from the scenarios that lead to release of radioactivity to the control room since our assessment of probability of chlorine gas release is very low. Thus, the benefits we identify are on the order of 2.5×10^{-7} reduction in core-melt frequency corresponding to a reduction of 10 man-rem.

Based on the benefits from scenarios A and B and our proposed ranking scheme this topic would be dropped. It should be noted that we agree that the control room habitability improvements will positively effect the operator actions during normal plant operation. The benefit associated with this scenario was not calculated and thus was not included in our ranking.

4.9 Topic 1.13: "BWR Vessel Water Level Instrumentation"

4.9.1 Background

The RPV water level indication at Millstone Unit 1 is based on several level gauges that use one of the two reference legs located in the drywell. In case of a LOCA, the drywell temperature could be very high. This, along with RPV depressurization can result in water in the reference legs flashing when the drywell temperature reaches the RPV saturation temperature. This effect results in a higher RPV level indication than actual water level in the vessel.

Such an erroneous level indication during a LOCA could result in an operator error in shutting off the makeup water too soon, resulting in core uncovery.

This problem only exists in case of a LOCA since during transients the reference leg temperature stays below RPV saturation temperature and thus no flashing occurs.

The utility is currently looking into several options for correcting this situation.

4.9.2 Utility Evaluation

The utility's evaluation of the effect of resolution of this topic on core-melt frequency consisted of looking at small-small, small and large break LOCAs. The accident scenarios consisted of a LOCA and the operator error due to erroneous level indication in maintaining level. For each LOCA sequence appropriate cognitive operator error was picked from the Millstone Unit 1 PSS. Combination of three sequences added to a core-melt frequency of 1.6×10^{-5}/year which correspond to 588 man-rem using the utility's public risk model. These values correspond to the reduction in core-melt frequency and total population exposure that could result if this problem is completely eliminated.

4.9.3 Review of the Utility Evaluation

The utility's analysis is simple and straightforward. In their analysis they have indicated that the reduction in core-melt frequency and population exposure are upper bound values since the cognitive operator error values in the Millstone Unit PSS are screening values. Although it is quite possible that the screening values used in Millstone Unit 1 PSS are conservative, this fact cannot be verified without more detailed analysis of the appropriate cognitive operator errors.

4.9.4 Conclusions

The utility's evaluation shows that if the problem with erroneous level indication during LOCA sequences is completely eliminated, a core-melt frequency reduction of 1.6×10^{-5}/year could result. Based on the screening cognitive operator errors used in Millstone Unit 1 PSS, the results of the utility's analysis of the topic is correct. This topic is ranked as medium significance based on our proposed ranking scheme.

4.10 Topic 1.16.1: "Millstone Unit 1/Millstone Unit 2 Backfeed"

4.10.1 Background

During a station blackout, the only means available to remove heat from the Millstone Unit 1 core is the isolation condenser system. If minor reactor coolant leaks exist for an extended period, a means to restore the RPV level may be needed, but the isolation condenser system cannot replace coolant to restore losses. One potential cause of an extended loss of all AC power is a fire in the switchgear room. Such a fire would disable all existing means of replacing lost coolant.

This topic addresses the issue of being able to provide a source of makeup to the reactor coolant vessel during periods of extended loss of power. The utility's proposed solution is to provide power to the Unit 1 Control Rod Drive (CRD) pumps from Millstone Unit 2 through a connection that does not pass through the Millstone Unit 1 switchgear room. Such a connection could also be designed to provide a secondary on-site emergency power supply for Millstone Unit 1. Therefore, this modification would provide a means to makeup lost primary coolant, using the CRD pumps, during a switchgear room fire and a redundant power supply for use during all station blackout events.

4.10.2 Utility Evaluation

The utility evaluation addressed the two benefits of the proposed modification separately. The benefits from mitigating the effects of a fire in the switchgear room were estimated to be significantly lower than the benefits from the mitigation of a station blackout. From a previous fire analysis, Northeast Utilities estimated a frequency of 3.5 E-5/yr for a fire in the switchgear room that would disable both AC power trains. This number was then compared to the frequency of a station blackout (8.2 E-3/yr), due to a loss of normal power and a failure of the gas turbine emergency power train and either the failure of the diesel generator emergency power train or the failure of the service water system (support states 7 and 4 in the Millstone Unit 1 PSS). The utility simply states that the benefit of the proposed modification will be dominated by the reduction in the station blackout frequency and does not quantify the benefits from the reduction in the frequency of switchgear room fire initiated events.

The benefits from reducing the station blackout events were calculated by reevaluating the support state split fractions to account for the reduction in the probability that power would not be available on both emergency AC power trains. (A final design for this modification has not been formulated but in their analysis the utility assumed that power could be supplied to either Millstone Unit 1 emergency AC train). The 0.2 probability of failure to successfully transfer power was primarily the sum of four factors: operator error in making the transfer at Unit 1 or at Unit 2, each assigned a failure probability of 0.05, and the failure of either of the Unit 2 diesel generators; each assigned a failure probability of 0.054 based on WASH-1400 data. Using this probability of failure to transfer power to Unit 1, effectively reduces the station blackout split fraction and frequency by 80%. The core melt frequency is thereby reduced by approximately 7%, or 5.5 E-5/yr. Using the utility's consequence model, this results in approximately a 2000 man-rem reduction over the remainder of the life of the plant.

4.10.3 Review of the Utility Evaluation

The fire frequency of 3.5 x 10^{-5}/year used for the switchgear room is in general agreement with the fire frequencies used in other safety studies for similar areas. Although these frequencies are plant specific, with the information currently available the value used in the utility's assessment would appear to be reasonable for a screening analysis. However, the analysis does not address the propogation of the fire initiator to the core damage that could result from a drop in reactor pressure vessel level due to leakage and inventory shrinkage. This was justified on the basis that the fire frequency was much smaller than the LNP-initiated station blackout frequency. However, the PSS considered proper operation of the isolation condenser and makeup to preclude a core melt. The probability of a core melt following a switchgear room fire would depend on, among other things, the size of any leakage and the amount of time needed to perform sufficient repairs to regain the capability to add inventory to the primary coolant. Based on additional information provided by the utility, it appears that the frequency of a core melt initiated by a switchgear room fire would be at least an order of magnitude or more less than the frequency of the fire. The amount of time available to restore power after the fire is nearly 50 hours assuming that the normal primary coolant leakage rate exists at the time of the fire. With this amount of time available, the probability of failing to recover power should be low enough to significantly reduce the core-melt frequency of switchgear room fire initiated events.

The benefit calculated for the LNP-initiated station blackout sequences is nearly 80% of the maximum achievable reduction that can be obtained by eliminating all station blackout contributors to the core melt sequences. The size of the reduction is limited by the reliability of the Millstone Unit 2 diesel generators and the probability of operator error in transferring power from one unit to the other. Since no procedures exist for this operation, the value of 0.1 used in the utility analysis is an effective screening value. WASH-1400 data was used for the Unit 2 diesel generators. Any attempt to refine these error probabilities would not be justifiable.

4.10.4 Conclusions

The benefit to be derived from this modification may be larger than that calculated by the utility. The fire in the switchgear room could be a more serious event than the analysis indicates. Several factors should be evaluated before it is assessed as being much less significant than the LNP initiated station blackout events.

The benefits in the station blackout scenarios are dependent upon the design of the backfeed and the procedures initiated to perform the backfeed. Obviously, the design must include provisions to eliminate the downside of connecting two nuclear power plants (fault propogation, etc.) and for the maximum benefit for both plants should allow for the transfer of power from either emergency power train in one unit to either power train in the second unit. From the utility analysis it appears that their conceptual design is intended to have this capability. With the proper design, it should be possible to reduce the station blackout frequency by the amount calculated by the utility, 5.5E-5/yr, and to achieve the corresponding reduction in public risk.

As noted in Section 4.2.4, this issue and the tornado missile issue address many of the same station blackout dominant accident sequences. Since the modification proposed in this issue reduces the frequency of more sequences than the tornado missile issue proposed modification, the core-melt frequency calculated above is used to rank this issue and the core-melt frequency reduction calculated for the tornado missile issue was recalculated to account for the impact of the backfeed modification. (If both modifications are made the total core-melt frequency reduction is approximately 6E-5/yr.) Based on our proposed ranking scheme, the core-melt frequency reduction of 5.5E-5/yr achieved through the backfeed modification is of high safety significance.

4.11 Topic 1.17: "Replacement of Motor Operated Valves"

4.11.1 Background

To mitigate the consequences of a pipe break inside or outside drywell, several Motor Operated Valves (MOVs) in the reactor or turbine building

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must change state. Following an accident some of these MOVs might have to function in a harsh environment due to high temperature, humidity or radiation. The concern in this topic is the environmental qualification of all MOVs that are relied upon to mitigate the consequences of a pipe break.

Currently there are 28 MOVs that are not environmentally qualified. These MOVs have been grouped by the utility in several common classes with similar proposed modifications for resolution of the required environmental qualification.

4.11.2 Utility Evaluation

The reduction in core-melt frequency and public risk as a result of the proposed modifications to the groups of MOVs was evaluated by the utility using a combination of methods A and B. These evaluations are briefly described below.

MOVs 1-LP-7A, B and 1-LP-10A, B

These valves are located in the reactor building. Successful operation of these valves is required for success of the alternate shutdown cooling system. In addition, successful function of MOVs 1-LP-10A and B is also required for the LPCI success. The utility argues that if the break is in the drywell, these valves can be exposed to high radiation if there is fuel failure. This could occur only if LPCI is failed, in which case neither LPCI nor alternate shutdown cooling system would be available.

If the break is in the reactor building and it is unisolable the operability of these valves would not be important since the coolant inventory will eventually be completely drained and core damage will occur. But if the break is isolable, the alternate shutdown cooling system can be used as a long-term decay heat removal system. For this scenario, it is assumed that following an isolable break in the reactor building, at least one of the four MOVs would fail leading to failure of the alternate shutdown cooling system. For this scenario, the feedwater and main condenser remain viable systems for heat removal.

The decrease in core-melt frequency as a result of qualification of these four MOVs was calculated using the following relationship:

$$\Delta CM = I_{\text{Isolable LOCA}} (Q_{FW} + Q_{MC}) (1-Q_{\text{Alt Soc}})$$

where:

$I_{\text{Isolable LOCA}}$ is the frequency of isolable LOCAs in containment = 1×10^{-5}/year

Q_{FW} is unavailability of the feedwater system = 6.65×10^{-2}

Q_{MC} is unavailability of the main condenser = 3.96×10^{-2}

$Q_{\text{ALT SDC}}$ is unavailability of alternate shutdown cooling system assuming the MOVs are operable = 0.161

Based on this equation, the reduction in core-melt frequency is 8.9×10^{-7} which corresponds to a reduction in population exposure of about 100 man-rem over the remaining life of the plant.

MOVs 1-LP-15A, B and 1-LP-16A, B

These valves are normally closed containment spray valves which are located in the containment building. The utility argues that if the break is outside containment where these valves could be exposed to high temperature and humidity, there is no need for operation of this system to depressurize the containment because the break is outside the primary containment.

For a break in the drywell these valves could be exposed to high radiation if there is fuel failure. This occurs if the LPCI system has failed in which case the operability of this system is irrelevant since it relies on LPCI pumps for its operation. Thus, environmental qualification of these valves should not have any effect on core-melt frequency or public risk.

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MOVs 1-CS-5A, B

These valves are normally closed spray injection valves located in the reactor building. The utility's evaluation shows that the primary benefit in qualifying these valves comes from the ability to isolate an interfacing system LOCA caused by an operator error in leaving two MOVs 1-CS-4A (or 4B) and 1-CS-5A (or 5B) open simultaneously during a quarterly test of 1-CS-5A (or 5B). It must be noted that there is a pressure interlock system which prevents the operator from opening these valves simultaneously unless the low pressure permissive signal exists. Thus, this interfacing system LOCA only occurs if this pressure interlock system is failed and the operator opens both valves simultaneously by mistake and check valve 1-CS-7A (or B) fails. The utility conservatively estimated the frequency of this event to be $5x10^{-6}$/year.

If MOVs 1-CS-5A or B are environmentally qualified, the operator can close them to isolate the interfacing system LOCA and thus the benefit from this is a reduction in core-melt frequency of $5x10^{-6}$/year.

For other scenarios environmental qualification of these MOVs would not have any effect on the core-melt frequency. This is due to the fact that for isolable breaks in the reactor building if this system is disabled, other systems such as feedwater system, isolation condenser and CRD flow can recover and maintain RPV level. For breaks in the drywell these valves can fail due to high radiation if there is fuel damage. This occurs if both LPCI and core spray systems have failed which makes the operation of these valves irrelevant.

MOVs 1-IC-2, 1-IC-3, and 1-IC-4

These valves are inlet and outlet valves for the Isolation Condenser (IC) system. Valves 1-IC-2 and 1-IC-3 are located in the reactor building and 1-IC-4 is located in the dry well. The only valve which is normally closed and has to open to initiate the operation of the IC system is MOV 1-IC-3. These valves receive a close signal upon detection of high flow which would indicate a break in IC piping.

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The MOV 1-IC-4 which is inside the drywell, cannot isolate a break inside the dry well. If the break is outside the drywell in the return line, 1-IC-3 is normally closed and will isolate the break. Thus, qualification of 1-IC-4 will not help in either of these scenarios.

MOV 1-IC-2 is located on the inlet side of IC Piping in the reactor building. This valve cannot isolate a break inside the drywell. For breaks on the inlet IC piping 1-IC-1 can isolate the line. Thus qualification of 1-IC-2 will only help if in this scenario MOV 1-IC-1 fails to close. The change in core-melt frequency as a result of qualification of MOV 1-IC-2 was calculated by the utility using this relationship

$$\Delta CM = I_{LOCA} \, Q_{IC-1} \, (1-Q_{IC-2})$$

where:

I_{LOCA} is the frequency of a break in IC piping = (2 sections) (2.0×10^{-7}/year-section) = 4.0×10^{-7}/year

Q_{IC-1} is the probability of failure of 1-IC-1 to close = 4.9×10^{-3}

Q_{IC-2} is the probability of 1-IC-2 failing to close assuming the valve is environmentally qualified = 3.0×10^{-3}

Using this relationship the environmental qualification of 1-IC-2 will decrease the core-melt frequency by 2×10^{-9}/year.

MOVs 1-CU-2 and 1-CU-3

These valves are part of the Reactor Water Cleanup (RWCU) System. Valve 1-CU-2 is located inside the drywell and 1-CU-3 is located in the reactor building. Both valves are normally open. These valves get a close signal upon detection of high flow in the RWCU system. The benefit of qualifying these valves is the ability to isolate a break in RWCU system piping.

If the break occurs inside the drywell neither valve can isolate the break. If the break occurs in the reactor building valve 1-CU-2 can isolate the break since this valve would not be exposed to a harsh environment. The benefit of qualifying valve 1-CU-3 comes from a scenario when valve 1-CU-2 fails. In this case decrease in core-melt frequency as a result of qualification of 1-CU-3 was calculated by the utility using the following relationship:

$$\Delta CM = I_{LOCA}\, Q_{CU-2}\, (1-Q_{CU-3})$$

where:

I_{LOCA} is the frequency of a LOCA as a result of a pipe break in RWCU system = (12 sections) (2.0×10^{-7}/year-section) = 2.4×10^{-6}/year

Q_{CU-2} is the probability of failure of valve 1-CU-2 = 0.11

Q_{CU-3} is the probability of failure of valve 1-CU-3 assuming it is environmentally qualified = 6.6×10^{-2}

Based on this relationship the reduction in core-melt frequency as a result of environmental qualification of MOV 1-CU-3 is 2.5×10^{-7}/year. This corresponds to a reduction of 18 man-rem in population exposure.

MOVs 1-RR-2A, B

The purpose of these valves, which are part of the recirculation line, is to prevent spillage of LPCI flow following a break in one of the recirculation lines. Given a break in one of the recirculation lines, these valves will close as a part of LPCI loop selection logic to prevent diversion of the LPCI from the core. The utility's evaluation has shown that the flow diversion is a problem when the size of the break is in the range of small and large break LOCAs. The reduction in core-melt frequency as a result of qualification of these valves is calculated by the utility using the following relationship:

$$\Delta CM = (I_{SB} + I_{LB})\, Q_{CS}\, (1-Q_{LPCI})$$

where

I_{SB} is the frequency of a small LOCA in the recirculation piping = $1x10^{-3}$/year

I_{LB} is the frequency of a large LOCA in the recirculation piping = $1x10^{-4}$/year

Q_{CS} is the unavailability of core spray system = $1.39x10^{-3}$

Q_{LPCI} is the unavailability of LPCI system = $4.45x10^{-2}$

Based on this relationship the decrease in core melt as a result of qualification of MOVs 1-RR-2A,B is $1.5x10^{-6}$/year.

MOV 1-MW-96A

This valve is located at the discharge side of the emergency condensate transfer pump which transfers water from the condensate storage tank to the hotwell following initiation of FWCI or feedwater system. The concern with this valve is the effect of high radiation that might occur following an accident and fuel damage. The utility argues that if FWCI or feedwater system are operable no fuel damage should occur. Thus, if there is fuel damage it implies inoperability of this system in either mode, in which case operability of MOV 1-MW-96A would be irrelevant. Therefore, it is concluded that adding a radiation shield for this valve would have no effect on core-melt frequency or public risk.

4.11.3 Review of the Utility Evaluation

Review of the utility's assessment of importance of environmental qualification of the MOVs discussed above has produced the following results.

For MOVs 1-LP-7A and B, 1-LP-10A and B, 1-LP-15A and B, 1-LP-16A and B, 1-RR-2A and B and MOV 1-MW-96A, the utility's analysis is adequate.

For MOVs 1-CS-5A and B, which are the normally closed spray injection valves, the utility has estimated the probability of an interfacing system LOCA of 5×10^{-6}/year. The basis for this frequency is not provided by the utility, but the scenario has been described as the failure of a pressure interlock system along with an operator error in leaving one of these MOVs and one of the two other MOVs 1-CS-4A or B which are in series with them, simultaneously open following a quarterly test and failure of check valve 1-CS-7A or B.

Frequency of occurrence of this scenario can be calculated as:

$$F \cdot Q_{PI} \cdot HE \cdot Q_{CV}$$

where

F is the frequency of initiation of the scenario = 8 based 4 tests of two trains

Q_{PI} is the failure probability of the pressure interlock = 10^{-3} This number is based on typical values for miscalibration of pressure sensors and relay faults.

HE is the operator error of commission = 10^{-3}, based on NUREG/CR-1278. (5)

Q_{CV} is the failure of the check valve, i.e., check valve reverse leakage = $1/2(3\times10^{-7}/hr)$ (12,960 hr/refueling) = 2×10^{-3}

Based on this relationship, the frequency of interfacing LOCA as a result of this scenario is calculated to be 1.6×10^{-8}/year which is much smaller than the utility's estimate of 5×10^{-6}/year.

For MOVs 1-IC-1 and 1-IC-2, the utility has calculated a decrease in core-melt frequency as a result of environmental qualification of these valves of 2.0×10^{-9}/year. This is based on a pipe segment break probability of 2.0×10^{-7}/year/section and 2 pipe sections. The utility has given WASH-1400 as the source of this pipe segment break probability. WASH-1400 only gives hourly failure rates for pipe segments (See Appendix III, Table III 2-

1). Based on WASH-1400 median hourly failure of $1x10^{-10}$/hr for pipe segments of greater than 3 inches in diameter and a conversion factor of 8.5 from median to mean (since this failure rate has an error factor of 30) and 8760 hours/year, the pipe segment failure frequency is calculated to be $7.4x10^{-6}$/year.

Based on this value the decrease in core-melt frequency as a result of environmental qualification of MOVs 1-IC-1 and 1-IC-2 is $7.2x10^{-8}$/year.

The same problem with pipe segment failure probability exists in the utility's calculation of benefits associated with environmental qualification of 1-CU-2 and 1-CU-3. In this case the decrease in core-melt frequency as a result of environmental qualification of these valves is calculated to be $1.0x10^{-6}$/year instead of $2.5x10^{-7}$/year evaluated by the utility.

4.11.4 Conclusions

Our review of the utility's analysis of benefits associated with environmental qualification of several MOVs shows that we are in agreement with the utility's results for MOVs 1-LP-7A and B, 1-LP-10A and B, 1-LP-15A and B, 1-LP-16A and B, 1-RR-2A and B and 1-MW-96A.

For MOVs 1-CS-5A and B we calculate a reduction in core-melt frequency of $1.6x10^{-8}$/year instead of the utility's $5x10^{-6}$/year.

For MOVs 1-IC-1 and 1-IC-2 we calculate a reduction in core-melt frequency of $7.2x10^{-8}$/year instead of $2.0x10^{-9}$/year calculated by the utility.

For MOVs 1-CU-2 and 1-CU-3 we calculate a reduction in core-melt frequency of $9.1x10^{-6}$/year as opposed to $2.5x10^{-7}$/year found by the utility.

Overall ranking of each of these improvements based on our proposed ranking scheme is shown in Table 4.3.

Table 4.3 Importance of the Environmental Qualification of Several MOVs Based on our Proposed Ranking Scheme

Motor Operated Valve	Change in Core-Melt Frequency Due to Environmental Qualification of the MOVs	Rank
1-CU-2 and 3	9.1×10^{-6}	Medium
1-RR-2A, B	1.5×10^{-6}	Low
1-LP-7A and B/ 1-LP-10A and B	9.0×10^{-7}	Drop
1-IC-1 and 2	7.2×10^{-8}	Drop
1-CS-5A and B	1.6×10^{-8}	Drop
1-LP-15A, B/ 1-LP-16A, B	----	Drop
1-MW-96A	----	Drop

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4.12 Topic 1.18: "ATWS: Upgrading of the Standby Liquid Control System"

4.12.1 Background

The NRC ATWS rule (10CFR50.62) recommends that all boiling water reactors have installed and operational a number of ATWS mitigating features. Presently, Millstone 1 has all of these features except that the standby liquid control system (SLCS) does not meet the recommended capability level. The rule recommends a SLCS capability of 86 gpm of a 13 weight percent sodium pentaborate solution; the Millstone 1 SLCS only has a capability of 43 gpm. The purpose of this issue is to evaluate the effect of upgrading the Millstone 1 SLCS, by presently unspecified means, to meet the capability recommended in the ATWS rule.

4.12.2 Utility Evaluation

In the utility's evaluation of this issue there were two major effects identified with the upgrading of the SLCS. These are 1) a more rapid reduction in core power and 2) a reduction in the amount of heat rejected to the torus, hence a lower peak torus temperature. No plant-specific analysis was performed; but, the utility referenced an analysis of the Browns Ferry plant (20) that showed that an increase in the SLCS flow rate, from 50 to 86 gpm, results in a reduction of the Browns Ferry peak torus temperature, from 195 degrees to 173 degrees. The utility felt, however, that the benefits of these effects could not be quantified using PRA techniques. The more rapid reduction of core power means that hot shutdown can be reached earlier if the operator follows procedures and lowers RPV water level. However, more significantly, a simplified torus heatup calculation was used to demonstrate that with an 86 gpm capacity SLCS, manipulation of the RPV level is not required. That is, the power reduction obtained from the 86 gpm capacity SLCS is comparable to the power reduction obtained from the 43 gpm capacity SLCS in conjunction with reduction of the RPV water level.

This benefit was evaluated by requantifying the ATWS contribution to core melt with the assumption that the operator action to lower RPV water level is not required. It was only necessary to evaluate those ATWS events with condenser isolation (loss of PCS) since only those events would be affected by upgrading the SLCS (see Section 3.3). The requantification was

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performed using a simplified equation (i.e., the ATWS event trees were not requantified) which compared the two cases. The 43 gpm case was modeled such that a core melt was assumed to occur if the operator failed to take proper action. The 86 gpm case was modeled such that the core melt was assumed to occur if the operator failed to take action to control the level and the SLCS failed to function. The result of this requantification was a reduction in the frequency of plant damage state TE2 by 6E-6/yr. This is equivalent to a risk reduction of about 450 man-rem over the life of the plant and a prioritized score of 1 out of 10.

4.12.3 Review of the Utility Evaluation

There are two major areas of the utility evaluation of this issue. The first is that we do not agree with the utility evaluation of ATWS events in the PSS. This is discussed in detail in Section 3.3 of this report, and that section presents our requantification of ATWS for two different base cases. It was necessary to perform our own analysis of this issue starting with the base cases presented in Section 3.3.

The other concern is with the assumptions used in the utility evaluation of this issue. That is, it is not sufficient to simply take the new base cases and apply the same technique used by the utility to develop a new result. Specifically, the following areas are significant:

- We do not agree that it is not possible to evaluate the effects of a lower peak torus temperature using PRA techniques. There are two notable potential benefits of a lower peak torus temperature. First, if the peak torus temperature is below 176 degrees, the operability of the low pressure injection pumps will not be compromised by a loss of sufficient NPSH, reducing the failure rate of the low pressure system. Second, if the peak torus temperature is below approximately 164 degrees, the operator will not have to take action to depressurize the RPV because the torus heat capacity temperature limit will not be exceeded. The latter effect will eliminate the core melt contribution from the operator failing to recognize the need to depressurize.

- The calculation used for the analysis failed to consider the dependence between two operator actions. For the 86 gpm case core melt was assumed if the operator failed to take action to control level and the SLCS failed to function. This implies that the action of initiating SLCS and that of controlling level are unrelated, and that the probability of the operator failing to initiate SLCS is essentially zero. In actuality, the decision to respond is unaffected by the upgraded SLCS, thus failure to respond by itself should still be considered to be a core melt. The only effect should be a reduction in the procedural error probability, since eliminating the need to control level simplifies the actions which must be performed by the operator.

- The analysis only evaluates the benefits without taking into consideration the potential down side. Specifically, the analysis assumes that all of the core melt frequency reduction in plant damage state TE2 from the installation of an 86 gpm SLCS becomes non-core melt. In actuality, some of that reduction should be added to other plant damage states (e.g., TL2). It is not correct to base the potential benefits on the full reduction in the frequency of plant damage state TE2 without considering the increase in the frequency of plant damage state TL2.

A requantification has been performed using the baseline analysis discussed in Section 3.3. The models presented in that section have been modified to reflect the potential improvement from the installation of an 86 gpm SLCS. There are three potential benefits to this installation. It may be possible to eliminate the need for the operator to reduce power by reducing the RPV water level, it may be possible to retain sufficient NPSH to utilize low pressure injection pumps, and it may be possible to eliminate the need for the operator to depressurize the RPV in order to retain sufficient torus heat capacity. It is very unlikely that all three of these benefits would be realized simultaneously simply by the installation of an 86 gpm SLCS. However, a bounding analysis can be performed by assuming that they will all be realized. In this way, the maximum potential benefit can be assessed without the need for plant-specific calculations.

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The analysis was performed by modifying the ATWS trees for loss of PCS, loss of feedwater, and loss of normal power initiators shown in Section 3.3. Only these transients are affected by the upgrade to an 86 gpm capacity SLCS. The following changes were made to account for the potential benefits discussed below.

- The failure probability of event Y1 was reduced from 0.16 to 0.031. This eliminated the probability that the operator would make a procedural error in controlling RPV level (0.13) since that action is assumed not to be required.

- The failure probability of event 073 was reduced from 0.13 to 0.0, since it is assumed that this action (to depressurize the RPV) is no longer required to retain sufficient torus heat capacity. Obviously, event I can also be eliminated from this part of the tree.

- Event E (failure of the low pressure pumps in manual) is redefined to include event I, since depressurization is required if the low pressure pumps are to be used. The failure probability is reduced from 1.0 to 0.013 since sufficient NPSH is assumed to be available for the pumps.

The results of the sequence requantifications are shown on Figures 4.4 and 4.5 and 4.6. In Section 3.3, two base cases were presented to account for uncertainty in the capability of the presently installed 43 gpm SLCS for mitigating ATWS events when the main condenser is isolated. Table 4.4 gives the ATWS contribution to the core melt frequency by plant damage state for each of the base cases and for the requantified case with an 86 gpm capacity SLCS. Table 4.5 gives the change in frequency for each plant damage state and overall for the installation of an 86 gpm capacity SLCS. The core-melt frequency reductions are calculated using both of the base cases evaluated in Section 3.3.

As previously stated, these results represent the maximum potential benefit of this change. While we generally do not like the use of bounding analyses of this type, the lack of a plant-specific analysis has made it necessary. The comparison with Browns Ferry is not valid because of

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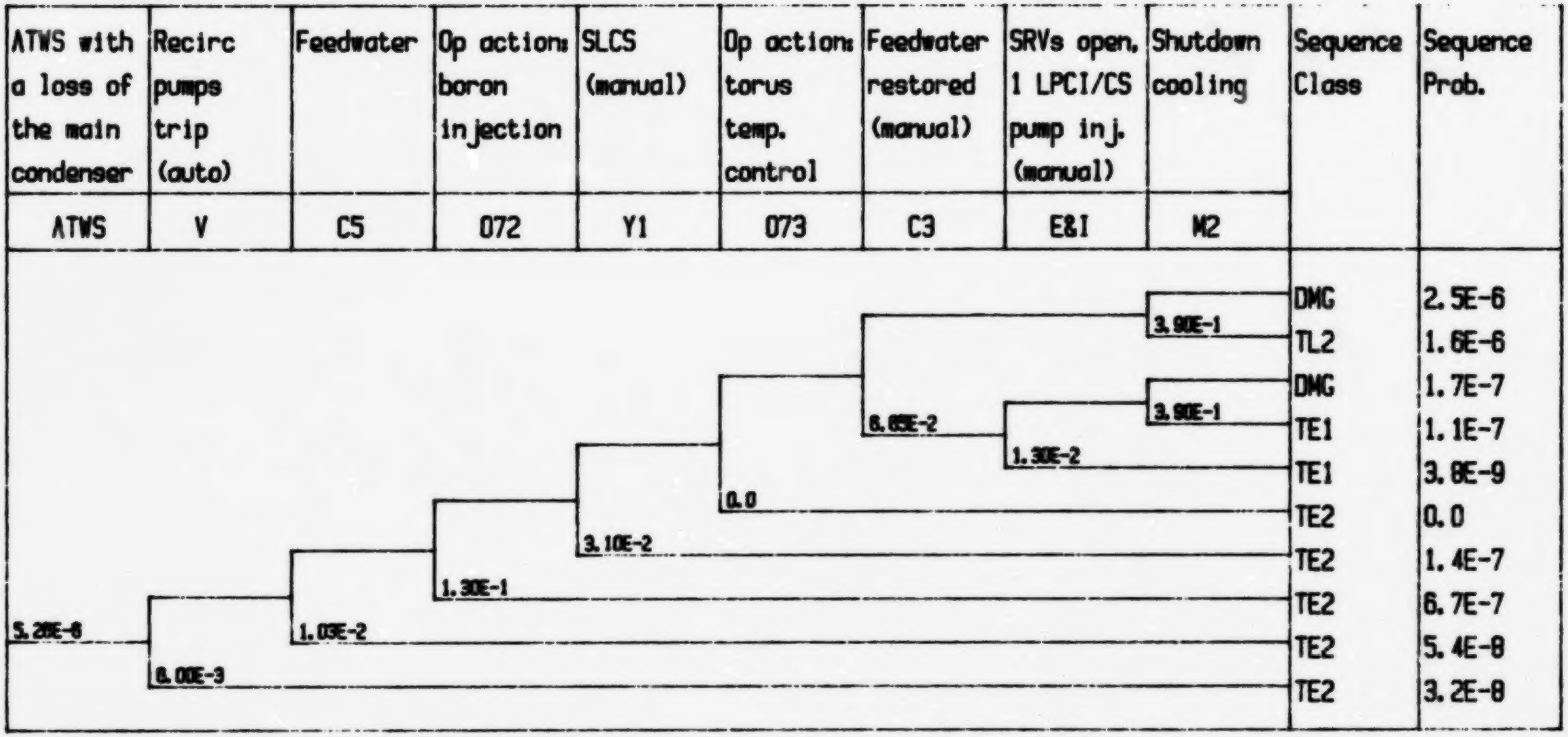
ATWS with a loss of the main condenser
Recirc pumps trip (auto)
Feedwater
Op action: boron injection
SLCS (manual)
Op action: torus temp. control
Feedwater restored (manual)
SRVs open, 1 LPCI/CS pump inj. (manual)
Shutdown cooling
Sequence Class
Sequence Prob.
ATWS
V
C5
072
Y1
073
C3
E&I
M2
3.90E-1
3.90E-1
6.65E-2
1.30E-2
0.0
3.10E-2
1.30E-1
1.03E-2
5.20E-6
6.00E-3
DMG
TL2
DMG
TE1
TE1
TE2
TE2
TE2
TE2
TE2
2.5E-6
1.6E-6
1.7E-7
1.1E-7
3.8E-9
0.0
1.4E-7
6.7E-7
5.4E-8
3.2E-8

Figure 4.4 ATWS Event Tree With Main Condenser Unavailable
(Loss of PCS - 86 gpm LSCS)

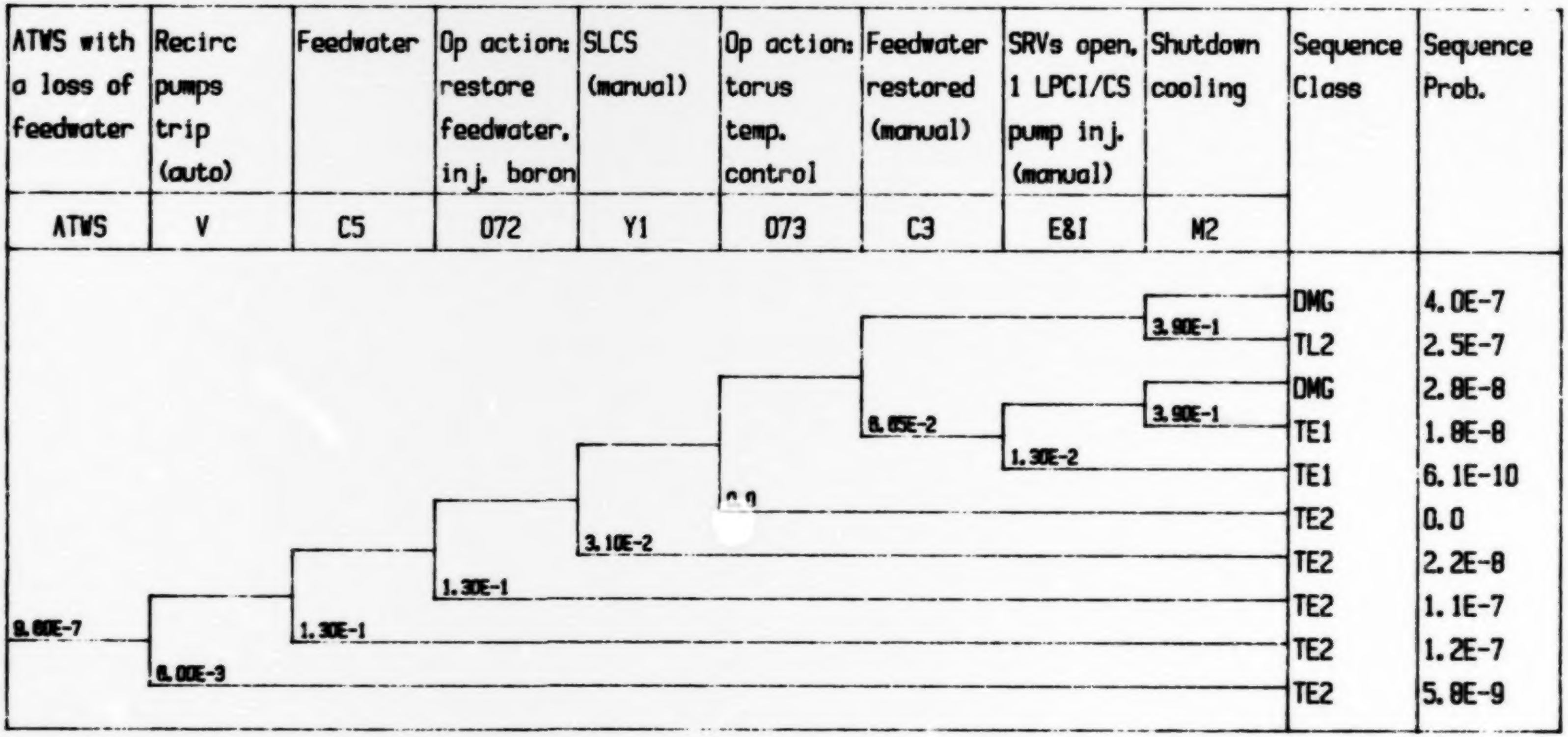
ATWS with a loss of feedwater
Recirc pumps trip (auto)
Feedwater
Op action: restore feedwater, inj. boron
SLCS (manual)
Op action: torus temp. control
Feedwater restored (manual)
SRVs open, 1 LPCI/CS pump inj. (manual)
Shutdown cooling
Sequence Class
Sequence Prob.
ATWS
V
C5
072
Y1
073
C3
E&I
M2
9.60E-7
8.00E-3
1.30E-1
1.30E-1
3.10E-2
0.0
8.65E-2
1.30E-2
3.90E-1
3.90E-1
DMG
TL2
DMG
TE1
TE1
TE2
TE2
TE2
TE2
TE2
4.0E-7
2.5E-7
2.8E-8
1.8E-8
6.1E-10
0.0
2.2E-8
1.1E-7
1.2E-7
5.8E-9

Figure 4.5 ATWS Event Tree With Main Condenser Unavailable
(Loss of Feedwater - 86 gpm SLCS)

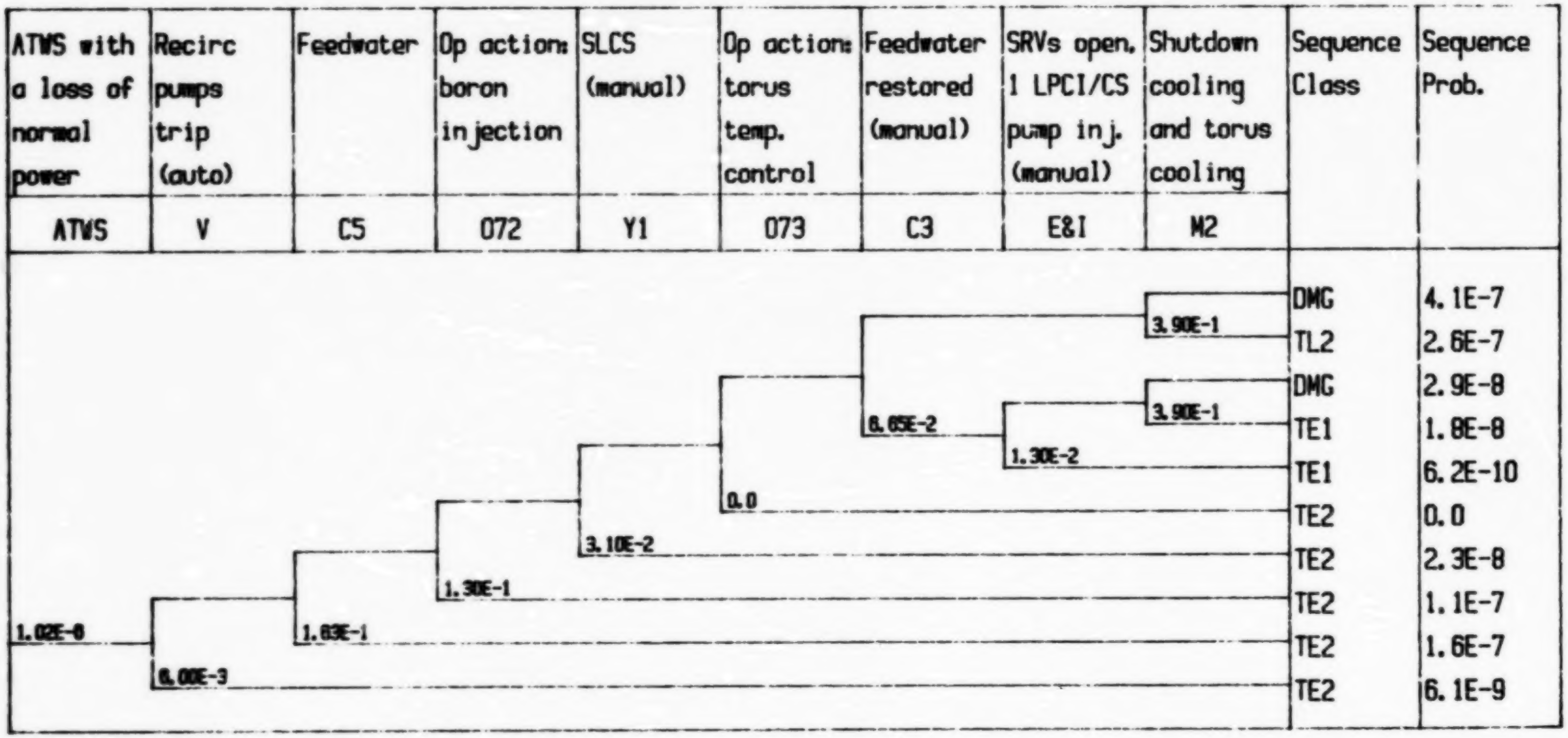
ATWS with a loss of normal power
ATWS
Recirc pumps trip (auto)
V
Feedwater
C5
Op action: boron injection
072
SLCS (manual)
Y1
Op action: torus temp. control
073
Feedwater restored (manual)
C3
SRVs open, 1 LPCI/CS pump inj. (manual)
E&I
Shutdown cooling and torus cooling
M2
Sequence Class
Sequence Prob.
1.02E-6
6.00E-3
1.63E-1
1.30E-1
3.10E-2
0.0
6.65E-2
1.30E-2
3.90E-1
3.90E-1
DMG
TL2
DMG
TE1
TE1
TE2
TE2
TE2
TE2
TE2
4.1E-7
2.6E-7
2.9E-8
1.8E-8
6.2E-10
0.0
2.3E-8
1.1E-7
1.6E-7
6.1E-9

Figure 4.6 ATWS Event Tree With Main Condenser Unavailable
(Loss of Normal Power Support State 1 - 85 gpm SLCS)

Table 4.4

Requantified ATWS Contribution to Core Melt

Plant Damage State	Frequency/Yr Credit for 43 gpm SLCS	 No Credit for 43 gpm SLCS *	 86 gpm SLCS
TE2	4.1E-6	8.4E-6	2.6E-6
TE1	2.9E-7	-	1.6E-7
TL2	2.6E-6	9.0E-7	3.3E-6
TOTAL	7.0E-6	9.3E-6	6.2E-6

* Column represents giving no credit for the use of a 43 gpm SLCS during isolation transients only. Credit is always allowed during non-isolation transients.

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Table 4.5

Change in Core-Melt Frequency from Installation of 86 GPM SLCS

Plant Damage State	Base Case # 1 (Credit for 43 GPM SLCS)	Base Case #2 (No Credit for 43 GPM SLCS)
	_ Freq/Yr	_ Freq/Yr
TE2	-1.5E-6	-5.8E-6
TE1	-1.3E-7	+1.6E-7
TL2	+7.0E-7	+2.4E-6
TOTAL	-9.0E-7	-3.2E-6

significant plant differences. The utility also stated in subsequent comments that simplified hand calculations indicated that the torus temperature "will be greater than 160°." In our opinion, the use of such "simplified hand calculations" is insufficient to resolve the issue. The estimated peak torus temperature is just too close to the critical temperatures which would affect the areas in question. It is possible, though admittedly not extremely likely, that all of the benefits we assumed would be observed. Thus, in the absence of a plant-specific ATWS analysis, we strongly feel the bounding analysis is warranted.

4.12.4 Conclusions

As can be seen from Table 4.5, the maximum potential core-melt frequency reduction from the installation of an 86 gpm capacity SLCS is about 3E-6 (Case 2). For Case 1, the core-melt frequency reduction is about 9E-7. Regardless of which case is selected, the issue would be ranked as low, using the ranking scheme from this report. A good part of this is due to the increase in plant damage state TL2 that results from the reduction in plant damage state TE2. This is caused by the high failure probability of the shutdown cooling (SDC) system. However, it should be noted that the overall result for base case 1 is very close to being a drop ranking, and as previously mentioned, our calculation is for a maximum potential benefit. If a plant-specific analysis of ATWS is performed and it shows that the presently installed 43 gpm SLCS is capable of mitigating an ATWS with the main condenser isolated and, further, it shows that installation of an 86 gpm SLCS will not provide all three of the benefits assumed in our analysis, then this issue would clearly be ranked as an issue to be dropped. Thus, if it is determined that this issue should be further pursued (i.e., the results from the bounding analysis are not low enough to eliminate this modification immediately) a plant-specific ATWS analysis should be performed to finalize the priority of this issue.

4.13 Topic No. 1.21: Fault Transfers

4.13.1 Background

GDC 17 as implemented by Regulatory Guide 1.6 requires that onsite electrical power supplies and their onsite distribution systems shall have sufficient independence to perform their safety function assuming a single failure. In the process of performing the Systematic Evaluation Program review of Millstone Unit 1, NRC questioned the propriety of using automatic bus transfer (ABT) switches in the plant electrical systems.

Currently Millstone Unit 1 utilizes several ABTs to provide redundant power sources to electrical equipment used in response to a potential accident initiator. While the use of ABTs provides some increased reliability of the equipment power supplies, it does introduce the possibility of transferring a fault from one emergency power train to the other. With a failure of the isolation breakers to function, such a transferrable fault could result in a failure of both onsite power sources.

Seven ABTs are currently in use at Millstone Unit 1 and are used to supply power to the following seven motor control centers and switchboards.

- 480 VAC EF-7, Diesel generator motor control center
- 120/240 VAC VAC-1, Vital AC switchboard
- 120/240 VAC IAC-1, Instrument AC switchboard
- 480 VAC MCC EF-3, LPCI injection valves, train B, are powered from this MCC
- 480 VAC MCC FE-3, train A of LPCI injection valves are powered from this MCC
- 125 VDC MCC EF-3, MCC control power
- 125 VDC MCC FE-3, MCC control power

4.13.2 Utility Evaluation

The utility states that one of the seven ABTs has been disconnected; the emergency feeder breaker to the ABT has been racked out to prevent auto transfer. Therefore, the ABT feeding MCC EF-7 cannot automatically transfer a fault from one power source to the other.

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Of the six remaining ABTs two are used to supply normal and emergency power feeds to the Instrument AC (IAC-1) and Vital AC (VAC-1) switchboards. The utility is planning to install regulating transformers on these feeds during the current outage. These transformers are designed with ground detectors that are to trip before the 480 VAC breaker is tripped thermally. The frequency of a demand on the 480 VAC breakers was calculated to be 5.4E-7/yr. (The product of the frequency of a bus fault, 8.8E-4/yr, and failure of the transformer trip, 6.14E-4 demand.) Since there are two buses, the utility doubled this number to 1.1E-6/yr.

This frequency is three orders of magnitude less than the estimated frequency of station blackout due to a loss of normal power and a failure of the onsite. The utility states that the bus faults therefore do not significantly affect the probability of losing both redundant sources of power.

In analyzing the impact of the four ABTs associated with MCCs EF-3 and FE-3, the utility calculated the increase in the core-melt frequency that would occur if the ABTs were disarmed. (The increased core-melt frequency is the result of a reduction in the reliability of the power supplies to the LPCI injection valves.) The results of the utility analysis showed a 0.4% increase in the core-melt frequency, an increase of 3E-6/yr. Using their consequence model this resulted in a 113 man-rem increase in the public exposure.

4.13.3 Review of the Utility Evaluation

The analysis of the potential for the transfer of an electrical fault from one power supply to another via IAC-1 and VAC-1 ABTs provides an accurate representation of the potential risks associated with the use of these ABTs. The calculated frequency of a fault transfer, 1.1E-6/yr, is significantly smaller than the expected frequency of station blackout.

However, the utility's analysis of the impact of the use of ABTs to supply power to the injection valves for the LPCI system appears to overestimate the impact of the removal of the ABTs while not estimating the potential negative impact resulting from their use.

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If the ABTs are removed from the LPCI system the reliability of the LPCI system will be reduced in those support states where one electrical bus is unavailable. For the sequences in which the LPCI system is automatically initiated (LOCA sequences) the system unavailability increases from .124 to approximately 0.6. This high unavailability is primarily due to the fact that only one injection path is usable in this mode of the system operation. When the system is initiated manually two injection paths are available, and the system unavailability increases from 5.06E-3 to 2E-2 when the ABTs are removed. Again, this is only for the support states in which one electrical bus is unavailable.

There are 22 accident sequences in the Millstone 1 PSS that include a failure of the LPCI system in the injection mode. When these sequences are requantified using the revised system unavailabilities the total core-melt frequency increases by approximately 4E-7/yr. The increase is due almost entirely to an increase in two loss of normal power initiated sequences. The sequences are a loss of normal power followed by failure of FWCI, failure of the SRVs to reclose or failure of IC/IC makeup, failure of the CS system, and failure of the LPCI system. (In this sequence the LPCI system is manually initiated.) These sequences are sequences 18 and 34 on the PSS loss of normal power event tree.

4.13.4 Conclusions

With the current design of the LPCI system, the removal of the ABTs which used to provide power to the injection valves would have a very slight impact on the unavailability of the system and the overall plant core-melt frequency. However, if the LPCI system is modified so that redundancy exists when the system is operated in the alternate shutdown cooling mode, the removal of these ABTs could have a greater impact on the core-melt frequency than that calculated in Section 4.13.3 above. (In the current design, the use of ABTs does not affect the reliability of the alternate shutdown cooling system since the system fails when one AC power supply is unavailable.) Since the modification to the alternate shutdown cooling system is under review as part of another ISAP issue, it is not possible to determine the impact of the ABTs removal on this mode of the LPCI operation at this time. The impact of the removal of the ABTs on the core-melt frequency due to the effect on the unavailability of the alternate shutdown cooling system should be greater than that for the LPCI injection mode; the failure of the cooling mode has a greater impact on the core-melt frequency than the failure of the injection mode.

While the removal of the ABTs will result in the elimination of any possibility of transferring faults from one electric power source to the other, this benefit should be offset by the reduction in the reliability of the LPCI system in both the injection and cooling mode. (Once the system is modified so that the two alternate shutdown cooling trains redundant.)

4.14 Topic 2.01: "LPCI Remotely Operated Valves 1-LP-50A and B"

4.14.1 Background

The two valves 1-LP-50A and 1-LP-50B are used to drain water from the torus to maintain the torus water level within the Technical Specification limits. After an accident, these two valves could be used to removed heat from the torus by draining hot water and adding cold water or they could be used during cleanup operations.

At present these two valves are manually operated valves. Under accident conditions with some fuel damage the valves may be inaccessible due to high radiation levels. The utility is proposing to add either motor operators or reach rods to allow for remote operation of the valves.

4.14.2 Utility Evaluation

The utility did not perform a quantitative analysis of this issue. They qualitatively compared the benefits and drawbacks to the proposed modification and assigned the issue a value of 0.1 on their public safety impact scale. The two possible benefits discussed are (1) the ability to use the torus drain lines in a "feed and bleed" type of operation to remove heat from the torus, and (2) the ability to use the torus drain line in clean-up operations following a severe accident with significant fuel damage. The first benefit was dismissed as being unachievable because the capacity of the drain lines, and the liquid rad waste system into which they drain, is too small to be of any use in a "feed and bleed" type of operation. The second benefit will help to reduce the financial consequences of

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a core damage accident although it will not affect the sequence of events leading to core damage.

The lone drawback to this issue is the possibility that the torus drain line valves could be unintentionally opened, or left open after their use to maintain the torus level. This would result in some "leakage" from the torus. The utility estimates that the leakage would not significantly affect the success criteria of the LPCI system.

4.14.3 Review of Utility Evaluation

Both the benefits and drawbacks to this modification appear to be relatively insignificant. The water level indication for the torus should provide adequate protection against an inadvertent draining of the torus during normal operation. The increased probability of inadvertent opening of these valves during normal or accident conditions should be relatively small, easily correctable (as noted in the utility assessment) and should not significantly affect the operability of systems needed to mitigate core melt sequences.

The benefit of this modification is limited to the use of the torus drain lines in clean-up operation. The bulk of this benefit would seem to be a reduction in the exposure to plant personnel during clean-up operations with only a minimal effect on the consequences to the public.

Since the benefits and drawbacks to this issue are insignificant, the use of engineering judgment to assign a safety significance (i.e., a score of 0.1 on the public safety impact scale) is reasonable.

4.14.4 Conclusions

The resolution of this issue would seem to have very little impact on the public risk from operation of Millstone Unit 1. The assessment of a value of 0.1 on the utility's public safety impact scale indicates that the utility sees a slight benefit from the modification. Since the drawbacks to the modification are so negligible, we feel that the assessment of a very small benefit is reasonable. Based on our proposed ranking scheme this issue is of such low safety significance that it should be dropped.

4.15 Topic 2.04: "High Steam Flow Setpoint Increase"

4.15.1 Background

The existing warranty for the Main Steam Turbine requires weekly testing of each of the Turbine Stop Valves. When any one Stop Valve is tested, the steam flow rates in the other three lines increases. In order to prevent closure of the Main Steam Isolation Valves (MSIV) on these lines which presently occurs at 120% of rated steam flow, the present procedure is to reduce core power from 100% to 90% during testing. Any time the reactor power level is changed there is a chance for a reactor transient resulting in a trip.

The utility wants to increase the MSIV closure setpoint from 120% to 140% of rated steam flow, so that a core power reduction will not be required during testing and the potential for a resultant plant transient and reactor trip will be eliminated. However, increasing the MSIV closure setpoint increases the need for detection and manual mitigative action in the event of steam line breaks in the setpoint range where automatic action would no longer be available.

4.15.2 Utility Evaluation

The possible increase in the core melt frequency as a result of the change in the MSIV setpoint from 120% to 140% of rated flow was evaluated by the utility by examining (1) the frequency of initiation of steam line breaks that could result in a flow rate between 120% and 140%, and (2) human and hardware failures to mitigate the consequences of this initiator.

The frequency of initiaton of the steam line break was evaluated by the utility using the following relationship

$$I_{SLB} = N_p \cdot \lambda_p \cdot 8760 \times 0.2$$

where:

N_p is the number of steam line segments downstream of MSIVs with a diameter greater than 3 inches.

λ_p failure rate of pipe segments = 1.0×10^{-10}/hour (WASH-1400).

The 8760 number is the number of hours per year and 0.2 factor comes from the argument that in the case of a double ended steam line break, the Venturis in these lines limit the flow rate to 200%. It was assumed that the break probability in the 100% to 200% range is uniform. Thus, the frequency of breaks corresponding to a flowrate from 120% to 140% is 1/5 the frequency of a double ended break. This frequency was calculated to be 7.0×10^{-6}/year.

Following this, two scenarios were postulated for core meltdown. First, if the operator fails to isolate the break but the feedwater continues to run, a late core melt with containment bypass will occur. The second scenario consists of successful operator action followed by feedwater failure. Based on a human error probability of 1×10^{-2} in failing to isolate the break and feedwater unavailability of 1.031×10^{-2}, an increase in core melt frequency of 1.4×10^{-7}/year was calculated. This results in an increase in public risk of 15 man-rem.

4.15.3 Review of the Utility Evaluation

There are two areas in the analysis of this issue where the utility's evaluation is either incorrect or questionable. The first is the use of an incorrect hourly failure probability of the pipe segments in the calculation of the initiating event frequency. The hourly pipe segment failure probability of 1×10^{-10}/hr taken from Table III of WASH-1400(3) is a median value with an error factor of 30. This implies that the mean value for this failure rate, which is the value that should have been used in this analysis, is about 8.5 times larger than the median value.

The second area is the assumption that the frequency of breaks corresponding to a flow rate from 120% to 140% of rated flow, is 1/5 the frequency of a double ended break. This implies a uniform break probability in this range. Based on industry experience to date it has been shown that the frequency of pipe breaks increases as the size of the pipe decreases. This fact is reflected in the initiating frequency of different size LOCAs used in PRAs for various plants. Thus, the frequency of break sizes

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corresponding to 120% to 140% flow rate would be expected to be higher than 20% of the frequency of the double ended pipe break.

Correcting the hourly failure rate of the pipe segments mentioned above results in an increase in the core melt frequency of $6.0x10^{-7}$/year instead of $7.0x10^{-8}$/year. This translates to an increase in public risk by 127 man-rem instead of 15 man-rem.

With respect to the second area, namely the frequency of break sizes corresponding to 120% to 140% flow rates, there are no specific data on the possible shape of the distribution. If, based on the earlier argument about the higher probability of smaller size breaks, one arbitrarily assumes that the frequency of breaks in this range is a factor of 2 larger than the uniform distribution; the increase in public risk would become about 254 man-rem.

4.15.4 Conclusions

In reviewing the utility's evaluation of this topic, there are two areas where the treatment of the issue did not seem to be correct. The first area is the use of the median value for the hourly failure rate of pipe segments in calculating of the steam line break frequency. Correcting this value results in an increase in the core melt frequency of $6x10^{-7}$/year (instead of $8x10^{-8}$/year) as a result of MSIV setpoint increase. This corresponds to an increase in public risk of 127 man-rem instead of 15 man-rem as calculated by the utility.

The second area is the assumption that the break frequency corresponding to 120% to 140% of the rated flow rate is 1/5 of the frequency of double ended pipe breaks. It was argued that based on available experience this break frequency should be higher than the 1/5 value. If this value is arbitrarily higher by a factor of 2; the increase in public risk would be about 254 man-rem. Due to the fact that this topic results in an increase in core-melt frequency and public risk, the topic is ranked as "drop."

4.16 Topic 2.06: "Main Condenser Retube"

4.16.1 Background

In 1982, Millstone Unit 1 was shut down as a result of a seawater intrusion into the primary coolant. The cause of the event was a failure of the main condenser tubing, allowing leakage from the circulating water system into the primary coolant. (The shutdown was manually initiated on high feedwater conductivity which also requires the isolation of main feedwater through the closure of the MSIVs.) Northeast Utilities is concerned that continued degradation of the main condenser tubing will result in another such incident in the near future. Additionally, the degradation of the tubing has an operational and economic impact in that periodic plugging of tubes and on-line sawdusting in the water boxes are necessary.

4.16.2 Utility Evaluation

To evaluate the safety impact of this issue the utility re-evaluated the accident sequences initiated by reactor transients, which include the loss of main condenser transients. The frequency of the loss of main condenser transient initiators was increased from 0.435/yr (the base case used in the PSS) to 0.568/yr to account for the main condenser tubing failure initiated events. This increase of 0.13/yr was based on two events in fifteen years. The first event was the one that occurred in 1983, the second was the event expected in the "near" future. The analysis assumes that this increase of 0.13 events/yr is the benefit that can be gained, i.e., the initiators that can be avoided, by retubing with titanium tubes. This increase in initiator frequency was calculated to increase the core-melt frequency from 8.07E-4/yr to 8.13E-4/yr, an increase of 6E-6/yr. The increase in the core-melt frequency was the result of the increase in four plant damage state frequencies. The four damage states and the increase in their frequencies are listed below. (The damage state classifications are explained in Section 2.2.2 of the Millstone 1 PSS.)

TE1	2E-6/yr
TE2	3E-7/yr
TI1	1E-6/yr
TL2	3.3E-6/yr

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Using their consequence model, Northeast Utilities calculated a public dose aversion of 50625 man-rem as the benefit from retubing the Millstone Unit 1 main condenser.

4.16.3 Review of Utility Evaluation

In their analysis, Northeast Utilities has assumed that a second seawater intrusion event will occur during the next fuel cycle. This is based on arguments that the condenser tubing is thinning and the failure probability for many tubes should be approaching unity. This argument is conservative and makes the utility analysis a worst case, bounding analysis.

A review of the dominant accident sequences in the Millstone Unit 1 PSS reveals that there are four sequences initiated by reactor transients (which include the loss of the main condenser). These sequences, the associated plant damage states, and the core melt frequency as calculated in the PSS are presented in Table 4.6. The core-melt frequency includes a contribution from the one seawater intrusion event that occurred in 1982. Replacement of the main condenser tubing with titanium tubing is supposed to eliminate this type of initiating event.

The utility assumption of two main condenser failures due to tube failures results in an initiator frequency of 0.13/yr (2 failures in 15 years). Using only the observed data, that is the one event in 15 years, the frequency of main condenser failure due to tube failures would be 0.067/yr. Accident sequences initiated by these events are the sequences that can be eliminated if the main condenser is retubed. In Table 4.6 the core-melt frequency for main condenser tube failure initiated accident sequences is provided for both of the above initiator frequencies. Also provided is the impact on public risk calculated using the utility's consequence model. Using our proposed ranking scheme, this issue would be ranked as of low safety significance.

(The impact we calculated from the dominant sequences using the utility suggested main condenser tube failure frequency of 0.13/yr is slightly less than that calculated by the utility. The apparent discrepancy is the result of the utility's ability to reassess all accident sequences while this review is limited to the dominant accident sequences.)

Table 4.6

Main Condenser Retube -- Impact Assessment

			Initiator: Main Condenser Tube Failure			
			Frequency = .13/Yr		Frequency = .067/Yr	
PSS Sequence #	Plant Damage State	Core Melt Frequency (/Yr)	Core Melt Frequency (/Yr)	Public Risk (Man-Rem)	Core Melt Frequency (/Yr)	Public Risk (Man-Rem)
Sequence 4	**TE1**	**3.5E-5**	**3.3E-7**	**12**	**1.7E-7**	**6**
Sequence 5	**TE1**	**1.4E-6**	**8.5E-7**	**32**	**4.3E-7**	**16**
Sequence 11	**TI1**	**3.2E-5**	**7.8E-7**	**29**	**3.9E-7**	**15**
Sequence 16	**TL2**	**4.5E-5**	**3.0E-6**	**338**	**1.5E-7**	**169**
ATWS	**TE2**		**3.0E-7 ***	**23**	**1.5E-7**	**12**
TOTAL			**5.2E-6**	**434**	**1.2E-6**	**218**

*** Taken from Northeast Utilities analysis**

4.16.4 Conclusions

The utility has performed what appears to be a bounding calculation on the impact of retubing the main condenser. The 506 man-rem reduction is the maximum public safety benefit that could be achieved through this plant modification, provided the new titanium tubing does indeed eliminate the problem. The minimum benefit from this plant modification is a reduction in core-melt frequency of 1.2E-6 corresponding to a reduction of about 218 man-rem in public exposure. Based on our proposed ranking scheme, the safety significance of this topic is ranked low.

4.17 Topic 2.07: "Sodium Hypochlorite System"

4.17.1 Background

Certain plant equipment cooling systems at Millstone Unit 1 use seawater as a cooling source, and inherently have problems with biofouling growth. The plant presently uses a chlorine gas injection system to control this problem. The chlorine gas for this injection system is located on-site and stored in 55 ton pressurized railroad tank cars. The utility is concerned that under certain circumstances a massive amount of chlorine gas could be released to the surroundings. The consequences of such an incident to plant personnel and the public residing near the site could be significant. Due to this potential impact on plant and public safety, the utility is considering replacing the chlorine gas injection system with a sodium hypochlorite system.

4.17.2 Utility Evaluation

In the assessment of the impact on public safety caused by a release of the stored chlorine gas, the utility has considered two scenarios: (a) the release of chlorine gas affects the operation of the plant in such a way as to induce a core-melt accident, and (b) the release of chlorine gas directly affects the public residing near the plant. For each scenario, two release categories were considered: (a) a massive release of chlorine gas caused by a catastrophic failure of the railroad tank car, and (b) an intermediate continuous release of chlorine gas resulting from a premature opening of the pressure relief valve located on the tank car.

The results of the utility analysis show that the first scenario, i.e., chlorine gas release leading to a core-melt accident, does not have a significant impact on plant or public safety. As described in the utility's analysis, the core melt frequency of this accident ($\lambda_{T,CR}$) is the product of the chlorine release probability (λ_{CR}) and the subsequent failure of the feedwater system and the isolation condenser or the isolation condenser make up system i.e.,

$$\lambda_{T,CR} = \lambda_{CR} \cdot Q_{FW} \cdot (Q_{IC} + Q_{ICMUP}).$$

The utility assumes that the operators manually trip the reactor and that soon after this action the operating staff is overcome by the chlorine gas and therefore there are no manual recovery actions possible. The postulated accident frequency is then linearly dependent on λ_{CR}, given $Q_{FW} \cdot (Q_{IC} + Q_{ICMUP}) = 5.1\text{x}10^{-4}$. In the worst-case impace secnario considered by the utility (an intermediate continuous release of chlorine gas), the chlorine release frequency, λ_{CR}, is estimated at $1.8\text{x}10^{-3}$/yr. Thus, the contribution to core melt frequency is:

$$\lambda_{T,CR} = (5.1\text{x}10^{-4})(1.8\text{x}10^{-3}/\text{yr}) = 9.2\text{x}10^{-7}/\text{yr}$$

For the catastrophic release of chlorine gas, λ_{CR} is estimated at $1.5\text{x}10^{-5}$/yr, resulting in a $7.7\text{x}10^{-9}$/yr contribution to the total core melt frequency. Therefore, the contribution to the core melt frequency from this accident is negligible.

For the second scenario, namely the effect of a release of chlorine gas on the public residing near the plant, the utility's analysis shows the possibility of a significant threat to the public health and safety. In terms of an equivalent radiation exposure, the consequences calculated for the postulated accident scenarios are as follows:

- 475 man-rems for a massive release of chlorine gas
- $1.13\text{x}10^4$ man-rems for an intermediate continuous release of chlorine gas due to premature opening of the pressure relief valve

As a result, the estimated public safety impact of removing this potential risk is ranked 10+ on the scale of 10.

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4.17.3 Review of the Utility Evaluation

The analysis performed by the utility appears to follow the methodology suggested in Regulatory Guides 1.78 and 1.95 for calculating the concentration of chlorine gas following an instantaneous (puff) release accident. The affected offsite population count considered prevailing meteorological conditions and surrounding population distribution. The conversion from a severe health effect experienced by the offsite population to an equivalent radiation induced latent cancer is reasonable, and would provide a basis for comparing the impact caused by a non-nuclear health impact issue to other nuclear-related safety issues.

While the chosen methodology for the analysis is generally acceptable, there still remains a number of concerns with regard to the parameters considered in the release model. First, as assumed in the utility's analysis the puff release of chlorine gas during the intermediate release is estimated at 25% of the content of the tank car. Assuming that the adiabatic flashing of the chlorine content is applicable in this case, in order to reach a 25% flashing the average temperature must be around 110°F. A more reasonable temperature average would be 70°F, and accordingly, the flashing amount would be 17.5% of the tank car content.

Secondly, for the intermediate release of chlorine gas accident, no exact assessment of the risk to the public safety is provided. It is assumed that because the concentration of the released gas in this case is 1/4 that of the catastrophic release, the risk is then approximately 1/4 the risk caused by the catastrophic release. This assumption is somewhat questionable since the impact on public safety does not necessarily vary linearly with the concentration of the released gas. It would be preferable to have the risk assessed based on the concentration calculated at various locations downwind from the release source, and the quantity of the gas released. It is assumed that this process was used to estimate the risk caused by the catastrophic release scenario, and if this is so, then the same process is expected to be used in the assessment of the risk caused by the intermediate continuous release accident.

Thirdly, our evaluation indicates that the failure rate for premature opening of a pressure relief valve presented in the report (2×10^{-7}/hr or

1.8×10^{-3}/yr) is questionable. According to the information provided by the Chlorine Institute (New York), there were no incidents of chlorine gas release involving premature opening of pressure relief valves on railroad tank cars in ten years. The database includes data gathered during 1971 - 1975 and 1980 - 1984, with an average of 8500 railroad tank cars in service per year. Using a zero-failure probability approximation, the failure frequency for premature opening of tank car pressure relief valve can be estimated at a 95% confidence level as follows:

$$\lambda_2 = \frac{N+1}{T_S}$$

N = 0 failure

T = 10 years

M = number of component in service per year (8500)

λ = mean failure rate

T_s = total service time = $(M)(T) = 8.5\times10^4$ yrs

$$\lambda_2 = \frac{1}{8.5\times10^4\ \text{yr}} = 1.2\times10^{-5}/\text{yr}$$

$f_2 = 2(N+1) = 2$ degrees of freedom

$\chi^2_2 = 5.991$ (at a 95% confidence level and $f_2 = 2$)

$$\lambda 95\% = \frac{\lambda_2\ \chi^2_{2,95\%}}{2} = \frac{(1.2\times10^{-5}/\text{yr})(5.991)}{2} = 3.6\times10^{-5}/\text{yr}$$

Thus, the potential impact to the offsite population due to the intermediate continuous chlorine release, in terms of equivalent radiation exposure calculated using this revised relief valve failure rate and the utilities equivalent radiation exposure model would be:

$(1\times10^4$ man-rem/latent cancer)(25 equivalent latent cancer)(25 yr) *
$(3.6\times10^{-5}$/yrs) = 225 man-rem

Finally, it appears that the utility does not consider the possibility of evacuation of the affected offsite population in the analysis. From additional information provided by the utility, it is indicated that the reason for not including the impact of any possible evacuation in the analysis is that there is little time for organizing an evacuation, and the affected population will be overcome by the gas before any rescue operation could be effected. Although this is reasonable for a worse-case accident scenario, the analysis might also consider other important conditions that could influence the movement of the plume and impact the factors that would determine if any evacuation would be possible. These conditions include the type of terrain on the plume path, the average wind speed and the existence of monitoring devices for early warning.

4.17.4 Conclusions

Based on our evaluation of the utility's analysis on this safety issue, it appears that the utility's methodology is acceptable. However, there remain a number of concerns with regard to the data on the failure rate of premature opening of relief valve, the possibility of evacuation, and the assessment of risk to the offsite public following an intermediate continuous release of chlorine gas. At best, the utility's results are illustrations of worst case scenarios coupled with doubtful component reliability data. In particular, the estimated 1.13×10^4 man-rem in terms of an equivalent public exposure resulting from an intermediate continuous release of chlorine gase appears to be too large. Our evaluation indicates an upper bound of 225 man-rem equivalent risk to the public for the same accident, based on a failure rate of 8.2×10^{-6}/yr instead of 1.8×10^{-3}/yr for the premature opening of the tank car pressure relief valve. As a result, the reduction in public exposure by replacing the existing chlorine gas only amounts to 700 man-rem or an equivalent ranking of 1.75 on a scale of 10. (The tank car rupture was calculated to contribute an equivalent population exposure of 475 man-rem.) Based on our proposed ranking scheme, this issue is ranked medium in safety significance.

4.18 Topic 2.08: "Extraction Steam Piping Replacement"

4.18.1 Background

The nuclear industry has noted a number of cases of severe erosion and failures of extraction steam piping. These failures result in a plant trip with potential loss of coolant outside containment. Further, breaks of this type pose a serious occupational hazard to operating and maintenance personnel who could be working in the area of this piping. Inspections performed at Millstone 1 have shown that significant erosion degradation exists in some of this piping. The purpose of this utility initiated issue is to evaluate the effectiveness of replacing this piping in the near term with new, more erosion resistant piping and associated hardware.

4.18.2 Utility Evaluation

Failure of this piping has the potential to result in two different initiating events. The first is a steam break outside containment (a form of interfacing systems LOCA). In order for this to occur, both the MSIVs and the turbine stop valves would have to fail to isolate following the extraction steam pipe break. The utility concluded that this is not very likely to occur and that this would have a negligible effect on risk. The second initiator is a loss of PCS (MSIV closure), which is what would occur if the above mentioned valves successfully isolated the RPV following the pipe break. If the piping is not replaced, it was assumed that the potential for a break would increase the overall frequency of this initiator, which presently has an estimated frequency of 0.435/yr.

In order to estimate the amount of the increase, the utility calculated the rate of erosion in the extraction piping. It was determined that if the piping was not replaced in the next refueling cycle, but rather field repairs were performed on piping where leaks are observed, wall thicknesses in most unrepaired welds would approach 0% by the end of the cycle. It was assumed that one pipe failure would occur in each 24-month refueling cycle until the piping was replaced (which would occur within 10 years in any case). This raised the loss of PCS frequency by 0.5/year over that time frame, to a total of 0.935/year. The change in risk was calculated over that 10-year period by using Method A of the utility's prioritization procedure. The plant damage state frequencies were recalculated by substituting the higher loss of PCS frequency in the computer model and generating new numbers. The results by plant damage state are shown in Table 4.7. The total core-melt frequency reduction is 2.3E-5. This equates to a risk reduction of 709 man-rem. The issue was therefore given a score of 1.75 out of 10.

Table 4.7

Impact of Not Replacing the Extraction Steam Piping at Millstone Unit 1

	Base Case (As-Is)	Without Extraction Steam Piping Replacement
M.S.I.V. Closure Frequency		
	0.435/Yr	0.935/Yr
Plant Damage State Frequencies		
TE1	$2.57\text{x}10^{-4}$	$2.62\text{x}10^{-4}$
TE2	$1.41\text{x}10^{-5}$	$1.53\text{x}10^{-5}$
TI1	$2.26\text{x}10^{-4}$	$2.30\text{x}10^{-4}$
TL2	$8.25\text{x}10^{-5}$	$9.49\text{x}10^{-5}$

4.18.3 Review of the Utility Evaluation

The evaluation of this issue appears reasonable. The conclusion that the likelihood of a failure of both the MSIVs and the turbine stop valves is very small is supported by the Millstone 1 IREP study. That study came to a similar conclusion when considering the potential for unisolated steam breaks outside the containment. Thus, we agree that the total benefit of replacing the extraction steam piping is in preventing an increase in the frequency of loss of PCS transients.

The analysis performed is very straightforward once the frequency of extraction steam pipe break is determined. Thus, we feel that the only question at issue is the determination of that frequency. If indeed the welds are in as bad shape as is presented by the utility, and we have no reason to believe that they are not, then the assumption that a pipe break will occur during the next refueling cycle is clearly reasonable. It is even conceivable that a larger number of breaks may occur if none of them is massive, that is, if they cause a trip but do not cause substantial damage which might force the utility into some immediate replacements. On the other hand, a massive break in the next cycle might result in action to immediately replace all the piping, thus reducing the 10-year (5-cycle) exposure time used in the calculation. All in all, we feel the number used by the utility is reasonable for a prioritization analysis. However, it is important to note that the results are directly proportionate to the exposure time and the number of breaks per cycle. For example, the benefit of replacing the piping now versus ten years from now might be about 700 man-rem, but the benefit of replacing them now versus waiting one extra refueling cycle (two years) is only one-fifth of that. Similarly, if it is likely that the degradation is so bad that field maintenance cannot prevent two breaks from occurring during each cycle, the benefit would be twice that value.

4.18.4 Conclusions

The reduction in large-scale core-melt frequency as a result of resolution of this topic is about 2E-5/year. According to the ranking scheme used in this report, the priority of this issue is medium.

4.19 Topic 2.30: "MSIV Closure Test Frequency"

4.19.1 Background

Once per month, the utility is required to test the operation of MSIV limit switches by closing each of the MSIVs 10% and verifying that the limit switch contacts close. These limit switches are part of the reactor protection system and provide an anticipatory trip of the reactor if the MSIVs close prior to the occurrence of conditions which will cause the trip on high flux or high pressure. The utility has become concerned that these tests might be increasing risk by increasing the frequency of loss of PCS initiating events since on two occasions during this testing a valve has overtravelled, resulting in a steam line isolation signal and closure of all MSIVs. The purpose of this issue is to determine if there is any benefit to reducing the test frequency to quarterly, and performing the test in conjunction with the 60% power full MSIV closure time test.

4.19.2 Utility Evaluation

The utility identified three potential effects of the reduced testing. First, by not testing the limit switches as often, the failure probability of the switches could increase. This effect was rejected on the basis that the RPS had sufficient backup trip functions such that any increase in switch unreliability would have no significant effect on overall RPS reliability. Second, the failure probability of the MSIVs could increase. This was rejected on the basis that the 10% closure test did not utilize the same parts of the valve actuator that were used for MSIV fast closure (isolation) and that the valve was only partially closed, which did not demonstrate its isolation function. Third, eliminating testing at 100% power would reduce the frequency of loss of PCS transients. The historical frequency of loss of PCS transients was recalculated excluding the two trips which occurred during testing, and it was determined that the reduced testing would yield a reduction in the loss of PCS transient frequency from 0.435/year to 0.27/year.

This issue was evaluated using Method A of the utility's prioritization procedure. The analysis consisted of substituting the new frequency for the base case frequency and requantifying the models. This resulted in a

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reduction in total core-melt frequency of 8E-6/year. About half of this was in plant damage states TE1 and TI1 while the other half of this was in damage state TL2. This corresponds to a risk reduction of 600 man-rem over the life of the plant and a prioritization score of 1.5 out of 10.

4.19.3 Review of the Utility Evaluation

Each of the three potential effects of reduced testing and the utility resolution of them was considered in the review. That the reduced testing would not effect the reliability of the RPS was easily verified. First, the RPS unavailability at Millstone is completely dominated by mechanical failure, especially considering that the plant has an alternate rod insertion (ARI) system. Thus a slight change in the reliability of the electrical portion of the system would not be expected to affect the overall reliability. Further, a review of the detailed RPS analysis in the Millstone 1 IREP study (1) showed that, even without ARI, the total elimination of this trip function would not affect the reliability of the electrical portion of the RPS. Thus, the utility assumption that sufficient backup to this trip signal exists is borne out by the review.

The assumption that reduced testing of the valves will not reduce the reliability of the valves is somewhat more questionable. While we agree that many of the potential valve failure modes are not tested during the monthly test, it does demonstrate that the valve disk and stem are not binding. Thus, reduced testing could lead to increased occurrence of this failure mode. However, even if the overall failure rate of the valves was tripled (as the test interval would be) we doubt that there would be a significant increase in failures to isolate. This is because with two MSIVs in each line and the backup isolation provided by the turbine stop valves, the isolation function is very reliable. Both the PSS and the Millstone 1 IREP study concluded that failure to isolate was a negligible contributor to risk, and it would take a vast increase in the failure probability to make it anything other than negligible.

Finally, the recalculation of the loss of PCS frequency by eliminating the two events which occurred during the 10% closure testing is intuitively reasonable.

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We do, however, have a problem with the results. While we do not question the reduction noted in the plant damage states presented, we question the absence of plant damage state TE2, which results only from ATWS events. The reduction of loss of PCS frequency would be expected to reduce this damage state also, since these initiators are a significant contributor to risk from ATWS. In order to estimate this additional effect, the modified loss of PCS ATWS analysis presented in Section 3.3 was utilized. The loss of PCS ATWS tree was requantified by replacing the baseline initiating event frequency (0.435) with the new value (0.27). This resulted in a reduction in the frequency of damage state TE2 of 7E-7. The other damage states on this tree were not considered since they are dominated by non-ATWS events which are already included in the utility evaluation.

4.19.4 Conclusion

As can be seen from Table 4.7, the reduction in large-scale core-melt frequency as a result of resolution of this issue is about 9E-6/year. Using the ranking scheme proposed, this topic would be ranked medium.

4.20 Topic 2.31: "LPCI Lube Oil Cooler Test Frequency"

4.20.1 Background

One of the major conclusions to be found in the Millstone Unit 1 PSS performed by Northeast Utilities is that failure of the long-term cooling function was the major contributor (contributing approximately 64%), to the core-melt frequency. One reason is the high unavailability calculated for the LPCI system in the alternate shutdown cooling (SDC) mode. This issue was initiated by the utility in an attempt to improve the reliability of the alternate SDC system.

Each of the two trains of the LPCI system contains two LPCI pumps. The lube oil for the two pumps' motor bearings is cooled by drawing water from the discharge line of the LPCI pumps. This cooling water passes through a single solenoid valve, 1-LP-52A for Train A and 1-LP-52-B for Train B, before the cooling line separates and connects to both pumps. Until recently the operability of the solenoid valves was inferred only by

Table 4.8

Change in Core-Melt Frequency from the Elimination of Monthly MSIV Testing

Plant Damage State	Change in Core-Melt Frequency (Per Year)
TE1 and TI1	- 4 E-6
TL2	- 4 E-6
TE2	- 7 E-7
TOTAL	- 8.7 E-6

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tests performed during each refueling outage. (This is the situation modeled in the PSS.) The high failure probability of these solenoid valves, tested during refueling outages only, was a significant contributor to the alternate SDC system unavailability.

The utility's proposed modification is to verify the operation of the solenoid valves during the monthly LPCI pump tests. The reduced test interval would shorten the failure detection time and reduce the failure probability for the solenoid valves.

4.20.2 Utility Evaluation

To evaluate this issue the utility first calculated the change in the failure probability of the solenoid valves due to the increased, monthly, testing. The valve failure probability used in the PSS is 2.75E-2 per demand. This is based on WASH-1400 data and a 22-month test interval. This failure probability was reduced to 1.25E-3 to take credit for the increased testing.

Using this lower solenoid valve failure probability the utility recalculated the unavailability of the alternate SDC system. (The effect on the LPCI system was not calculated, because the utility felt the effect would be small.) The reduction of the failure probability for these two solenoid valves reduces the system unavailability for support state 1, from 0.148 to 9.55E-2. The reduction in the system unavailability is this large because failure of either solenoid valve results in a system failure.

The reduced system unavailability was used in a recalculation of the core-melt frequency. The core melt frequency was reduced from 8.07-E4/yr to 6.86E-4/yr, a reduction of 1.21E-4/yr. Approximately 80% of this reduction occurs in plant damage states SI1 and TI1 (both intermediate core melts) and the remainder occurs in AL2, SL2, and TL2 (late core melts). The calculated public risk benefit is 5500 man-rem.

4.20.3 Review of the Utility Evaluation

A review of the dominant sequences in the Millstone 1 PSS indicates that there are nine dominant accident sequences whose frequency would be affected by the resolution of this issue. (The valve failure probability reduction and the reduction in the system unavailability are both appropriately modeled.) These nine sequences contribute 3.8E-4/yr to the Millstone 1 PSS core-melt frequency. If the alternate SDC system failure probability is reduced from .148 to .0955 in these sequences, the core-melt frequency is reduced by 1.2E-4/yr as shown in Table 4.9. This is in agreement with the utility results. However, the utility estimate of the reduction in public risk appears to be low. Using the utility's consequence model we have calculated a benefit of approximately 6500 man-rem from the core-melt frequency reduction of the dominant sequences. These results are also presented in Table 4.9.

4.20.4 Conclusions

The utility assessment of the benefit, in terms of reduced core-melt frequency, that the increased test frequency of the LPCI lube oil cooler solenoid valves provides is reasonable. However, using the utility's consequence model SAIC has calculated a public risk benefit nearly 20% greater than that calculated by the utility.

Despite the slight differences in the utility and SAIC evaluations of this issue, it is apparent that the increased testing of the LPCI lube oil cooler solenoid valves significantly reduces the core-melt frequency and public risk of Millstone Unit 1. Based on the proposed ranking scheme, this issue would be ranked as being of high safety significance.

It should be noted that this issue addresses only part of a much larger issue, the reliability of the Millstone 1 long-term cooling systems. The resolution of the lube oil cooler test frequency issue does impact the potential benefits that could result from the resolution of ISAP issue 2.28 "Long Term Cooling Study." However, this issue (Issue 2.31) does not address all of the problems that need to be addressed in the long term cooling study, since failure of the long-term cooling function is still a dominant contributor to the plant core-melt frequency.

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Table 4.9 Change in Core-Melt Frequency as a Result of Increase in Lube Oil Test Frequency

PSS Sequence #	Plant Damage State	PSS Frequency (/yr)	Modified Frequency (/yr)	ΔCore Melt Frequency (/yr)	Public Health Multiplier	ΔPublic Risk person-rem
7	SI1	1.6E-4	1.0E-4	5.7E-5	.5	2100
9	TI1	4.0E-5	2.6E-5	1.4E-5	.5	520
10	TI1	3.4E-5	2.2E-5	1.2E-5	.5	450
11	TI1	3.2E-5(1)	3.0E-5	2E-6	.5	75
12	TI1	2.1E-5	1.4E-5	7.4E-6	.5	280
13	AI1	1.6E-5	1.0E-5	5.6E-6	.5	210
16	TL2	4.5E-5	2.9E-5	1.6E-5	1.5	1800
17	TL2	1.9E-5	1.2E-5	6.7E-6	1.5	750
18	SL2	8.3E-6	5.4E-6	2.9E-6	1.5	330
Total		3.8E-4	2.5E-4	1.2E-4		6500

(1) Only 5E-6/yr of this number is affected by this issue. The remainder is the result of system failures in support state 3 where this modification yields no benefit for the alternate SDC system.

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APPENDIX D

RECOMMENDED GUIDELINES TO RESOLVE ADDITIONAL AREAS FOR INTEGRATION

Additional Areas for Integration

One of the objectives of ISAP is to provide a mechanism for prioritizing all licensing actions, pending actions and licensee initiatives such that a cost-effective implementation program can be implemented. Toward that end, PSAs provide one of the yardsticks to help to determine the priority of each action. The PSA is used to estimate the relative change in core melt frequency and risk associated with the implementation of an action. PSAs can also be used to suggest new actions or disclose ways of reducing uncertainty in the assessment.

Recognizing the importance of a good PSA to the understanding of nuclear power plant characteristics and to the reduction in risk that may be achieved, the staff has evaluated five areas (reliability assurance, severe accidents, station blackout, Mark I containments and external events) that may help to expand the present scope of the Millstone Unit 1 PSA for a greater understanding of operating characteristics and a possible reduction in plant CMF.

I. Reliability Assurance

A strong reliability assurance program can be beneficial to a utility because it monitors changes in equipment reliability and tracks problems that have occured at other operating plants. The Millstone Unit 1 PSA was quantified using certain equipment and human reliability assumptions. A reliability assurance program can help to assure the validity of the PSA assumptions.

One of the keystones in assuring public health and safety is a commitment for reliable and well maintained systems and components at nuclear power plants. NNECO has informally discussed its reliability assurance program with the staff in the context of its proposed living PRA program. The following discussion outlines areas that the staff believes should be part of a reliability assurance program. NNECO has indicated that its proposed living PRA program already includes many of these recommendations.

(1) The Millstone Unit 1 PSA should be maintained as a living document. The PSA should be updated periodically as new data (e.g., component failure frequency, human error frequency, or new initiating events) or new analytical techniques become available.

(2) The lessons learned from the PSA should be incorporated into operator training, especially on the simulator. Operations and maintenance personnel should be taught pattern recognition for the more vulnerable plant configurations based on PSA results.

(3) Importance measures for use by engineering and operations personnel should be developed so they can better evaluate operational occurrences (at Millstone 1 and other plants), train operators, and evaluate the safety significance of areas of potential non-compliance, inspection report findings, and technical specification changes.

(4) Failure modes and effects analyses on human errors in the conduct of maintenance, surveillance, normal and emergency procedures and technical specifications should be performed to develop safety insights.

(5) Emergency, off-normal, and normal operating procedures should be reviewed in light of PSA findings.

(6) The PSA and NNECO's reliability data base should be used to determine what additional components, if any, should be scrutinized during operator plant walkthroughs each shift.

(7) Reliability techniques should be used to determine appropriate test frequencies. Maintenance and testing activities of components determined to have high importance measures should be carefully reviewed. Surveillance tests should be reviewed to determine if dominant accident contributors receive adequate attention in the test procedures.

(8) Monitoring and trending programs should be established for components determined to have high importance measures, especially where components have a history of failures. Levels at which intervention should occur should be determined for components of high importance.

(9) Importance measure analysis results should be made available to Northeast Utilities' quality assurance organization as an aid in focusing on areas that are important to risk.

(10) The Millstone 1 PSA should be used in an interactive mode during the design process for design changes at Millstone 1.

(11) The PSA should be used to estimate the effect on safety of proposed Technical Specification changes.

(12) The PSA should be an integral part of any proposed changes in the integrated implementation schedule.

The staff recommends a medium implementation priority for these items.

II. Severe Accidents

PSAs are performed to seek a better understanding of core damage sequences and reduce their frequency and risk. Many of the dominant sequences in the Millstone Unit 1 PSA are beyond design basis accidents. The staff believes that NNECO can make several cost-effective modifications to Millstone Unit No. 1 emergency procedures and plant equipment which should have a significant effect on preventing/mitigating a severe accident.

On August 8, 1985, the Severe Accident Policy Statement was published. It described how the Commission intends to resolve safety issues related to severe accidents. The Severe Accident Policy Statement states three major goals, which are: reduction of the estimated core damage reduction of high consequence accident sequences; and reduction of fission product releases.

In an effort to reduce estimated core damage and identify risk outliers, NNECO has completed the Millstone Unit 1 PSA (a level 1 PRA). NNECO has already made several plant and procedural modifications which were motivated by the PSA results. The modifications include:

- revised surveillance procedures for the LPCI pump motor bearing lube oil cooling;
- revised preventive maintenance program to improve the emergency service water to LPCI cross-tie valve reliability;
- modified valve operator and switch logic for MOV 1-IC-3 (isolation condenser condensate return line valve) and replaced 1-IC-3 with a smaller valve;
- corrected LPCI and core spray pump throttling procedures;
- corrected LPCI loop selection wiring error on the LPCI system injection valves;
- modified emergency procedures to bypass, at the discretion of the operator, potential drywell cooler lockout;
- changed preferred power source on valve SW-9 (isolates nonessential service water cooling loads); and
- replaced valve operator for 1-IC-1 (isolation condenser steam isolation valve).

NNECO also continues to evaluate emergency and normal operating procedure modifications, technical specification changes, and hardware modifications using insights from the PSA.

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Implementation of many of the ISAP topics will result in a reduction of core damage frequency. Both the staff and NNECO found the following ISAP topics to contribute most to estimated core melt frequency reduction:

- Topic 1.01 - Gas Turbine Generator Start Logic Modifications
- Topic 1.16 - Appendix R (Unit 1/Unit 2 Backfeed)
- Topic 1.18 - ATWS
- Topic 2.24 - Offsite Power Systems

The staff would also include the following ISAP topics in that list because of their importance to the severe accident issue, especially related to station blackout:

- Topic 1.09 - Regulatory Guide 1.97 Instrumentation (drywell spray flow measurement);

- Topic 1.17 - Replacement of Motor-Operated Valves (drywell spray)
  - Topic 1.24 - Emergency Power (gas turbine maintenance program);

  - Topic 1.24 - Emergency Power (gas turbine maintenance program);

  - Topic 1.50 - Isolation Condenser Startup/Makeup Failures;

  - Topic 1.51 - Failure to Restore Main Condenser; and

  - Topic 2.30 - MSIV Closure Test Frequency

III. Station Blackout

In addition, regarding significant reduction in core melt frequency, the staff recommends that the issue of station blackout, as addressed under USI A-44, be included in the scope of the Millstone Unit 1 ISAP. The issue of station blackout is particularly pertinent at the Millstone site given the historical loss of offsite power during two hurricanes.

By letter dated July 31, 1986, NNECO submitted the "Final Report for the Integrated Safety Assessment Program for Millstone Unit No. 1". In Section 4.1 of that report NNECO addressed the issue of station blackout and stated "that the unique characteristics and features of Millstone Unit No. 1 are such that the overall risk of station blackout is acceptably small, will be further reduced by plant modifications planned for the near-term, and... the plant compares favorably with the proposed requirements currently before the Commission."

The staff agrees that the estimated station blackout frequency will be reduced by near-term plant modifications, especially the Appendix R However, the staff does not agree that the core melt frequency resulting from station blackout at Millstone Unit No. 1 as estimated in the PSA is acceptably small (4E-5 per year due to station blackout; 2E-4 per year for all loss of offsite power events) or that Millstone Unit No. 1, as presently configured, compares well with the 1E-5 per year goal for station

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blackout frequency. The staff recommends that additional actions should be taken at Millstone Unit No. 1, beyond those proposed by NNECO, to improve prevention and mitigation of station blackout events.

The staff expects that implementation of ISAP Topic 1.16 - Appendix R (Unit 1/Unit 2 Backfeed, See Section 3.3.16) will have a significant effect on the estimated station blackout frequency. The staff also expects that implementation of the following ISAP Topics will have an affect, although less, on the estimated station blackout frequency.

- Topic 1.01 - Gas Turbine Generator Start Logic Modifications
- Topic 1.02 - Turbine Missile Protection
- Topic 2.17 - 4.16kV, 480V and 125VDC Plant Distribution Protection
- Topic 2.24 - Offsite Power Systems

The ability to cope with a station blackout will provide an increase in the defense in depth concept at Millstone Unit No. 1. The PSA analyzed station blackout taking into account the capability of systems and components including DC battery capacity, condensate storage tank capacity, compressed air capacity, and instrument and control requirements. Also, the ability to maintain adequate reactor coolant inventory during a station blackout was addressed as well as required operator actions.

The draft regulatory guide on station blackout provides guidance on how to calculate the minimum time a nuclear power plant should be able to withstand and recover from a station blackout event. The regulatory guide recommends that the acceptable duration to cope with a station blackout be based on the following factors:

(1) The redundancy of the onsite emergency AC power system;

(2) Frequency of loss of offsite power;

(3) Probable time needed to restore power; and

(4) The reliability of each onsite emergency AC source.

Redundancy - Millstone Unit No. 1 has two emergency AC power sources (one diesel and one gas turbine generator) of which one is required in order to provide AC-powered decay heat removal systems.

Frequency - There have been two extended loss of offsite power events in the last 11 years at the Millstone site.

Restoration - NNECO estimates that, although offsite power was not restored to Unit 1 for 20 hours and to Unit 2 for 26 hours following Hurricane Gloria in 1985, power could have been restored in 3.5 and 5.5 hours respectively. NNECO estimates that, although offsite power was not restored for 11.5 hours at Unit 1 and for 24 hours at Unit 2 following Hurricane Belle in 1976, offsite power could have been restored in 5 hours. The staff finds that a reasonable estimate, given the experience stated above, of the time needed to restore offsite power would be about 4.75 hours.

Reliability - The Millstone Unit No. 1 diesel generator has a history of high reliability (probability that diesel starts and loads = 0.993). The gas turbine generator, however, is a more valuable emergency power source because it alone can power a feedwater train in the event of a loss of offsite power. The gas turbine reliability is very close to the recommended minimum 0.95 start reliability in the draft station blackout regulatory guide.

Based on the guidance given in the draft Regulatory Guide on station blackout and Generic Letter 84-15, the staff recommends that the following actions be taken to help prevent and mitigate the effects of station blackout. The staff ranks the implementation priority of the following recommendations as high.

- Maintain reliability/testing/maintenance records for the diesel generator and the gas turbine generator at Millstone 1.

- Itemize the demands and failures experienced by the units. A demand is defined as either (1) any attempted start of the diesel or gas turbine generator for the purpose of supplying AC power under emergency conditions (2) a test which is any attempted start of a diesel or gas turbine generator for surveillance testing during nonemergency conditions. (NOTE: Tests performed during maintenance periods do not count as demands. Tests performed during a requalification program should be counted as demands.)

  A diesel or gas turbine generator failure is defined as (1) a failure of the generator to start on demand within the period specified in its technical specification; or (2) a failure of the generator to supply the AC power specified in its technical specifications to the emergency bus for the period called for.

  Valid demands and failures should be determined in accordance with the criteria of Section C.2.e of Regulatory Guide 1.108.

- If the gas turbine generator has a failure to demand ratio of two failures in the last twenty valid demands (2/20) or the diesel generator has three failures in the last twenty demands, the test frequency of the affected unit should be increased to once every 7 days. This frequency should be maintained until no more than one failure occurred in the last twenty valid demands and seven consecutive demands have been successful.

- If the gas turbine generator or diesel generator at Millstone 1 has a failure to valid demand ratio of six failures in the last 100 valid demands (6/100) or three failures in the last 20 valid demands (3/20) respectively, Northeast Utilities should provide a written report to the NRC within 14 days of the latest failure that analyzes all failures, determines root causes of failures, if possible and identifies actions taken or to be taken to correct the root causes of failures to achieve a general improvement of emergency power reliability at the site. The schedule for implementation of each action should be submitted.

Once NNECO has submitted an initial report detailing how generator reliability will be improved, NNECO need submit only a supplemental report within 14 days after each valid failure for so long as the affected generator continues to violate the reliability criterion (3/20 or 6/100). The supplemental report need update only the failure/demand history for the affected generator since the last report for that generator. The supplemental report should also preesent an analysis of the failure(s) with a root cause determination, if possible, and should delineate any further procedural, hardware, or operational changes to be incorporated into the improvement program and the schedule for implementation of those changes.

- If the gas turbine generator has a failure to valid demand ratio of eleven failures in the last 100 valid demands (11/100) or the diesel generator five failures in the last 20 valid demands (5/20) the affected generator should be "disqualified" and should be subject to a requalification program. The requalification program should be a series of fourteen consecutive valid tests (demands) without a failure. NNECO should be allowed two consecutive attempts to achieve the acceptable test series. During requalification testing a generator should not be tested more frequently than once in any 24-hour interval.

After generator has been successfully requalified, subsequent repeated requalification tests should not be necessary as long as the generator continues to violate the criterion (5/20 or 11/100). If the generator cannot be requalified as defined above, NNECO should inform the NRC of what steps it plans to take to improve emergency power reliability.

With the cummulative time for operation of the emergency power system with one of the generators inoperable for greater than the following limiting time periods the licensee should initiate an orderly retreat to COLD SHUTDOWN (operating mode 4).

Note: A generator should be considered to be inoperable from the time of failure until the first valid successful demand is completed.

Note: NNECO should establish maximum inoperability limits (cummulative time)for the diesel and gas turbine generators, taking into consideration the manufacturer's recommendations and previous maintenance and repair experience. Every reasonable effort should be made to restore individual generators to operable status as soon as possible within that time period.

- Limits on the total yearly duration that the onsite emergency power system should function with the diesel generator or gas turbine generator in the inoperable status should vary as a function of the number of failures in the last 100 valid demands for the operable generator in the system. The following table could be used to determine the maximum total time in the last 365 calendar days that the onsite emergency power system may function with the diesel generator or the gas turbine in the inoperable status mode.

No. of failure in the last 100 valid demands for the operable generator.	Maximum total time that the onsite emergency power system may function with the gas turbine or diesel generator in the inoperable status the last 365 calendar days
11	0
5	8 days
4	16 days
3	28 days

The staff ranks the following recommendations as medium:

- NNECO should integrate all emergency procedures for actions to restore emergency AC power with plant specific technical specifications (See response to Supplement 1, "Requirements for Emergency Response Capability", Generic Letter No. 82-33). Procedures should include all actions necessary to restore offsite power and use of nearby power sources such as portable generators. Procedures should consider loss of offsite power due to grid undervoltage and collapse, weather-induced power loss, and preferred power distribution system faults (e.g., lightening, or maintenance errors) that could result in the loss of normal power to essential switchgear buses.
- NNECO should document to NRC the capability of Millstone Unit No. 1 to withstand and recover from an 8 hour station blackout. The NNECO submittal should highlight operator actions necessary to allow the plant to cope with a station blackout lasting 8 hours.

Any additional modifications resulting from these recommendations should be prioritized and incorporated into an update of the integrated implementation schedule.

IV. Mark I Containments High Consequence Sequences and Fission Product Releases

The second and third severe accident goals address reducing high consequence accident sequences and fission product releases. The Commission stated in the Severe Accident Policy Statement that the examination of individual reactor risks will "include specific attention to containment performance." The examination of severe accident risks at BWR plants with Mark I containments has led the staff to conclude that a number of worthwhile and significant improvements in containment performance (in both design and operation) can be made at low to moderate cost.

What is at issue is the capability of the Mark I containments to perform a mitigating safety function as long as practicable during very low probability, beyond design basis accidents when the consequences of containment failure may be very significant. This issue is important for the Mark I containments.

For most of the core melt accidents considered in the staff's analysis, the core is postulated to melt, interact with steam, water, and the structural features in the vessel and coolant system, melt through the vessel, and attack the concrete and structural features of the lower containment. Depending on the sequence of events, the containment has the potential to fail either before or after vessel melt through.

BWR containments respond to heatup of the fuel in the vessel directly or indirectly. The direct transfer of energy is through pipe breaks or through blowdown into the suppression pool. Indirectly, radiant heat is transferred through the vessel and piping. The blowdown or depressurization process, and the use of the relatively large quantity of suppression pool water as a heat sink and fission product scrubbing device, act in combination with the structural capability of the containment (including penetrations) to mitigate the high temperatures, pressures, and radioactivity released in a core melt. Core melt scenarios have been identified, however, which can produce conditions in the containment that could lead to failure. There is evidence that BWR containments are capable of withstanding substantially higher stresses than those for which they are currently expected to fail and this evidence can be capitalized on to provide additional protection to the public at low to modest cost. The longer a containment can remain intact following a core melt accident, the greater the reductions in the radioactivity released can be achieved. Actions that can be taken to prevent overpressure failure of containment before the fission products are adequately attenuated include such items as operator actions to vent the wetwell space above the suppression pool, and use of reliable drywell spray capability.

In a core melt accident with fuel centerline temperatures in excess of 5000 degrees F, fission products are released from the fuel. The noble gases and the more volatile species are released as the fuel melts down into the vessel and combine with the in-vessel structural materials. Finally, after melting through the vessel, refractory materials may be released during interactions of core debris with concrete on the floor of the containment.

The amount of radioactivity that could be released to the environment in core melt or degraded core accidents has been the subject of considerable analysis for a number of years. Present estimates (NUREG-0956)

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for Mark I BWRs indicate that substantial quantities of important fission products can be released in a core melt accident and these analyses provide clues that suggest that releases can be reduced by a number of actions to enhance containment performance.

The core of a contemporary BWR with a Mark I containment, at full power, contains about five billion curies of radioactivity. Severe accident releases to the environment for a Mark I have been estimated to exceed 40% of such important fission products as iodine and cesium. This release fraction can be reduced.

Because the Millstone site has a high population density, because of its susceptibility to loss of offsite power and because of the potentially high conditional failure probability of Mark I containments, the staff recommends that NNECO address implementation of the following guidelines and criteria to prevent and mitigate severe accidents. The staff has broken down the criteria into sets with high, medium and low implementation priority. These criteria were developed from BNL report A-3825R. This ranking is the proposed priority for implementing the studies to address the criteria. Any modifications resulting from the studies should be prioritized for implementation in an update to the integrated implementation schedule.

A. Drywell Spray Function (High)

(1) Drywell spray should commence when the containment reaches a predetermined value calculated in accordance with the BWR Emergency Procedures Guidelines (EPG) or before the drywell temperature reaches the value at which ADS is qualified.

(2) Drywell spray should be terminated when the containment pressure decreases below a predetermined value calculated in accordance with the EPG.

(3) During a station blackout and eventual loss of dc power, drywell spray should be provided by a backup system (e.g., the diesel-driven fire pump with sufficient flow capacity and discharge head) with a diverse water supply and source of power independent from the normal and emergency power sources.

(4) Equipment designated for drywell spray should be capable of performing its functions in a reliable manner under the predicted containment conditions associated with sequences for which operation of the containment spray is needed for mitigation.

(5) Operator training and emergency procedures should specify the flow paths and specific components to be aligned and their required positions for initiating drywell spray. If a backup system and/or equipment is to be utilized, operator training and procedures should identify the flow paths and specific actions required for any temporary system cross connections.

(6) Operator training and procedures should specify the plant parameters that will prompt the operators to initiate and terminate the drywell spray. Training and procedures should

be consistent with the time required to align the system and components both manually and automatically as severe accident sequence events unfold.

(7) The heat removal rate provided by the drywell spray related components should be sufficient to remove decay heat

B. Wetwell Venting Function (High)

(1) For accident sequences where wetwell venting has been assessed to be beneficial, venting should commence, except for a station blackout scenario, when containment pressure reaches the venting pressure setpoint. In selecting the containment pressure setpoint, the following functions should be assured:

a. the ultimate containment pressure would not be exceeded,

b. the backpressure acting on the safety relief valve assemblies would not prevent the valves from performing their function,

c. the vent valve assemblies would not be prevented from performing their function.

During a station blackout, wetwell venting should commence in accordance with the criteria developed using the EPG (i.e., following onset of the transient before depletion of the station batteries).

(2) If manual initiation of wetwell venting is required, the time required to perform this function should be taken into account in the training and procedures to preclude the potential for exposing personnel to the harsh environment. Otherwise, the containment venting valve(s) should be powered from a source independent from the plant emergency power sources.

(3) Wetwell venting should be terminated in accordance with the criteria specified in the EPG to maintain the containment pressure above atmospheric and, therefore, prevent deinerting.

(4) Operator training and emergency procedures should specify the plant parameters that will prompt the operators to make preparation, commence and terminate the venting sequence. The training and procedures should also be consistent with the required actions and timing of those actions so venting will commence immediately when required (see Criteria B.1 and B.2). The training and procedures should further specify the flow path(s) available for venting, specific components to be

aligned, and the required positions/states for these components. The training and procedures should specify how to proceed if termination of venting is not possible especially as they relate to emergency management.

(5) Venting capacity should be greater than the predicted rate of increase of the containment pressure during sequences where venting is anticipated and should meet the requirements of Criterion B.1.

(6) The criteria for filtering is dependent on the potential for bypassing the suppression pool. Whether the suppression pool is bypassed or not, the radiological release should be reduced by an order of magnitude compared to no filtering. Except for that portion of the containment atmosphere that is present prior to initiation of the severe accident, the venting flow path should ensure that all media to be vented passes through the suppression pool thus providing filtering by the pool.

(7) Equipment designated or used to support wetwell venting should be capable of performing that function in a reliable manner for a sufficient period to include vaporization release phase of core/concrete interaction under the predicted environmental and fluid dynamic loads associated with the venting commencement.

(8) Support systems for the venting valves (electrical power for a motor-operated valve, air and/or spring/piston for an air-operated valve) should be of sufficient capacity that at minimum power or pressure provided, the delivered force from the actuator is greater than the resulting fluid loads for all angles of opening.

(9) The effects of possible hydrogen burn, radiation or steam on reactor building equipment located outside of the primary containment should be considered for venting through all possible flow paths. If equipment important to the mitigation of accident sequences are jeopardized by venting, alternate venting paths should be identified, assessed, and judged not to be detrimental for venting.

(10) The effects of possible containment depressurization on the emergency core cooling pump net positive suction head should be assessed. Alternate injection sources which are unaffected by venting should be identified.

(11) Wetwell venting should be terminated when significant radioactive noble gas inventory begins to appear in the wetwell airspace such that the projected offsite releases approach a level that could be life threatening.

C. Prevent Deinerting (High)

Basis: With the use of drywell sprays and wetwell venting during a severe accident, the possibility exists that as the accident progresses, temperatures and pressures will be reduced to the point that venting flow will reverse and normal reactor building air will be drawn into the containment. This could form a combustible mixture in the containment.

Criteria: In order to prevent the formation of a combustible mixture in the containment, the following should be met:

(1) Operator training and emergency procedures should specify that wetwell venting be terminated before containment pressure decreases to a value above atmospheric pressure calculated in accordance with the BWR Emergency Procedures Guidelines.

(2) Equipment designated for wetwell venting should be capable of either being remotely operated under predected severe accident conditions or all manually operated wetwell venting equipment should be accessible. The time required for manual operation of each component should not exceed sequence mitigation requirements or acceptable limits of personnel environmental exposure.

(3) Operator training and procedures should specify the methods for monitoring and controlling containment pressure and the oxygen content. The instrumentation to be monitored, conditions under which operator action is required, equipment to be used, and specific actions to be taken to prevent the formation of a combustible mixture should be specified for severe accident conditions.

D. Primary System Injection (High)

(1) A method of providing makeup to the primary system during a station blackout lasting for at least 8 hours should be provided. The use of the diesel driven fire pump in conjunction with the feedwater heater drains may be adequate.

(2) If the diesel driven fire pump is to be used, it should be designed to perform in a reliable manner and be capable of operating in the predicted environmental conditions associated with station blackout.

E. Operator Response During ATWS (Medium)

(1) Compliance with the ATWS Final Rule dated July 26, 1984 is required.

(2) The systems and equipment required to be interfaced by the operator as specified by this guideline should be designed to perform their function in a reliable manner accounting for the predicted environmental conditions and fluid dynamic loads.

(3) Operator training and emergency procedures should specify the plant parameters that are indicative of ATWS and the actions to be taken to verify that the reactor recirculation pumps have tripped automatically. Additionally, they should specify the actions to be taken if automatic trip of the reactor recirculation pumps does not occur.

(4) Operator training and emergency procedures should ensure reactor water level control during ATWS. Note: This unique control requires actions which conflict with mitigating actions for all other accidents, which call for flooding the reactor pressure vessel to ensure that the core is covered.

(5) Operator training and emergency procedures alert the operator that reactor water level indicators may be inaccurate and should provide another means of verifying water level.

(6) The Automatic Depressurization System (ADS) should be capable of being defeated reliably by the operator prior to its automatic initiation. Operating training and procedures should address the possible reluctance of operators to defeat a safety system, in particular, the need to inhibit the ADS immediately after SLCS initiation attempt.

(7) Operator training and procedures should specify the responsibilities of operating staff crew members and clarify how information will be exchanged among them. In particular, instrumentation readings may have to be relayed between the crew member(s) operating the control boards and the senior reactor operator coordinating the crew's response to the accident.

(8) Operator training and emergency procedures should ensure that manual initiation of SLCS injection is accomplished as required during an ATWS. Operator training and procedures should specify the plant parameters indicative of manual SLCS actuation and the actions to be taken and verification to be made to ensure that SLCS was actuated.

F. Emergency Core Cooling Injection (Medium)

(1) Operator training and procedures should specify methods and actions for heat removal via alternative injection path(s) in conjunction with wetwell venting for severe accident conditions when high suppression pool temperature precludes use of primary emergency core cooling injection paths.

(2) For the alternative injection path(s), it should be demonstrated that the flow is sufficient to preclude core damage for events with loss of containment heat removal.

(3) If local operation of the equipment is required, the time required to perform these functions should be consistent with the time available to help prevent core damage and account for personnel exposure to the predicted severe accident environment.

G. Suppression Pool Bypass (Low)

(1) Core debris control should be accomplished for low pressure sequences. Physical confinement of core debris for high pressure sequences is unlikely to be successful.

(2) In view of the uncertainty with regard to the amount of core debris leaving the vessel, the core debris control method should be capable of confining 100% of the core, the entire reactor pressure vessel bottom head and the total core support structure.

Guidance:

A suitable debris control method would be a concrete or magnesium oxide curbing of sufficient height to block the pedestal doorways and confine the debris. The curbing should be anchored in place to resist the hydrostatic head of the core debris. The curbing should have sufficient strength and thickness to withstand core debris attack for at least (TBD) hours.

(3) Primary system leakage should be ensured to be directed through the suppression pool unless containment filtering is provided.

H. Reactor Pressure Vessel Depressurization (Low)

1. The RPV should be capable of being automatically depressurized as required by design for all dominant accident sequences.

2. Operator training and procedures should ensure reliable manual control of RPV depressurization.

3. The ADS should be capable of initiation and operation under the environmental conditions associated with the dominant accident sequences. In particular the ADS should be capable of operating under the maximum pressure anticipated before venting.

V. External Events

Many safety assessments which have included external events (e.g. earthquakes, fire, hurricanes, tornados, flooding, transportation of hazardous materials) have estimated that external events may be important or dominant contributors to core melt frequency and risk. The potential for high offsite consequences is heightened for events such as earthquakes and hurricanes where evacuation may be impeded.

Each of the external events analyses has areas of significant uncertainty (e.g., the return period of large earthquakes) or conservatism, some areas perhaps larger than those associated with most internal event core melt frequency analyses. Because of this, the staff does not endorse the use of bottom-line numbers from external events analyses. Rather, the staff finds that important insights regarding the relative importance of failure modes and weak links can be established.

NNECO has submitted a probabilistic fire analysis and internal flooding analysis for Millstone Unit No. 1 which are under review by the staff. The staff recommends that NNECO use a state-of-the-art code similar to the ESP-NOAH code package (NUREG/CR-2678) in its flooding analysis.

It is the staff's judgement for Millstone Unit No. 1 that of the external events beyond fire and internal flooding, only seismic issues warramt further analysis at this time. Although seismic concerns were reviewed under SEP, this work was strictly an audit review, not state-of-the-art analyses.

The staff recommends that NNECO, drawing on the seismic analysis experience in SEP, perform fragility analyses to form a basis for incorporating seismic external events into the PSA. Alternatively, NNECO could perform a seismic margins analysis to find vulnerabilities. The staff ranks the implementation priority of the seismic fragility analyses as medium.

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The Integrated Safety Assessment Program (ISAP) was initiated in November 1984, by the U.S. Nuclear Regulatory Commission to conduct integrated assessments for operating nuclear power reactors. The integrated assessment is conducted on a plant-specific basis to evaluate all licensing actions, licensee initiated plant improvements and selected unresolved generic/safety issues to establish implementation schedules for each item. In addition, procedures will be established to allow for a periodic updating of the schedules to account for licensing issues that arise in the future.

This report documents the review of Millstone Nuclear Power Station, Unit No. 1, operated by Northeast Nuclear Energy Company, which is one of two plants being reviewed under the pilot program for ISAP. This report indicates how 85 topics selected for review were addressed and presents the staff's recommendations regarding the corrective actions to resolve the 85 topics and other actions to enhance plant safety. The report is being issued in draft form to obtain comments from the licensee, nuclear safety experts, and the Advisory Committee for Reactor Safeguards. Once those comments have been resolved, the staff will present its positions, along with a long-term implementation schedule from the licensee, in the final version of this report.

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